MONTANA POWER COMPANY

Load Forecast and Integrated Least Cost Resource Plan

March 1993

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The Montana Power Company

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TABLE OF CONTENTS

1.0 INTRODUCTION

This document represents The Montana Power Company's (MPC) electric utility 1993 Integrated Least Cost Resource Plan (ILCP) as required by the Montana Public Service Commission. It provides an overview of the ILCP process using a resource base that includes existing MPC resources, surplus resources from other western utilities, and the resources identified from *MPC's Request for Proposals for Supply-side and Demand-side Resources*. It describes the ILCP process and the competitive bid solicitation. The ILCP process includes input from the Conservation and Least Cost Planning Advisory Committee (CLCPAC) and the public. This document summarizes MPC's 1993 Load Forecast, MPC's demand-side resources planning, and will be used in the Relicensing Application for the Missouri-Madison Hydroelectric Project.

The ILCP process is a dynamic process that is progressively refined through experience. MPC's ILCP process was developed in recent years through a collaborative effort with the CLCPAC, which was formed in 1988 and includes representation from individuals and groups interested in energy policy and the regulatory process in Montana. The CLCPAC meets regularly with MPC representatives to provide input to resource planning and conservation acquisition activities and other utility matters.

The foundation of MPC's ILCP process is a rigorous resource and resource plan evaluation coupled with a thorough risk and uncertainty evaluation which are combined by a Multi-Attribute "Decision Rule" that emphasize a balance among various attributes. The attributes included in MPC's Decision Rule are customer, environmental, and investor concerns, reliability, risk and uncertainty, and societal costs. MPC used these attributes to identify a resource plan that would minimize societal cost and would be capable of addressing the different challenges of an uncertain future in a least cost manner. The purpose of the Multi-Attribute Decision Rule is to address and balance numerous objectives, some of which conflict; consequently, the resource plan that minimizes societal total costs may not be the plan that provides the lowest customer rates.

MPC's **first integrated** least cost resource plan, which was published in March 1992, was developed using the ILCP methodology defined in the *Integrated Least Cost Planning Report and Recommendations to Montana Power Company and Montana Public Service Commission* (published in 1990) by the CLCPAC; and draft versions of the Montana Public Service Commission's (MPSC) rules and guidelines. MPC's *1992 Load Forecast and Integrated Least Cost Resource Plan* identified a future need for resource by the mid 1990s; it prompted a request for proposal for additional resources; and it provided the foundation of the analyses presented in this document.

While the overall ILCP process has not changed significantly since 1992, the ILCP process used to develop the *1993 Load Forecast and Integrated Least Cost Resource Plan* was enhanced in two ways: (1) it included the Request for Proposal (RFP) process, and (2) it included input from the public that was gathered from a customer questionnaire and six public meetings.

The 1993 ILCP process consisted of five major steps. These are listed below and diagrammed on Illustration 1 in Appendix A.

1. Identify Resources
2. Evaluate Individual Resources
3. Combine Selected Resources into Resource Plans
4. Analyze Selected Resource Plans
5. Select Best Plan and Best Resources

A detailed diagram of the 1993 ILCP Process is provided in Illustration 2 in Appendix A; each step is explained in more detail below.

1. Identify Resources

   The starting point of the ILCP process was the *1992 Load Forecast and Integrated Least Cost Resource Plan* (1a). The identified resources included surplus resources from other western utilities (1b), the supply-side and demand-side resources identified from the Request For Proposal (RFP) (1c), and MPC supply-side and demand-side resources identified in the *1992 Load Forecast and Integrated Least Cost Resource Plan* (1d). This step identified 84 resources totaling over 5,500 MW of capacity.

2. Evaluate Individual Resources

   This step included screening the bid proposals for completeness (2a) and performing a Static Analysis, consisting of an Individual Resource Analysis, Environmental Analysis, Technical Analysis, and Transmission Analysis on all resources (2b). Based on the results of the resource screening and Static Analysis, 21 resources were selected (2c).

3. Combine Selected Resources into Resource Plans

   Existing MPC resources and the 21 future resource alternatives were configured into groups called resource plans (3b). Each plan was designed to meet the projected customer needs as defined in the 1992 base case load forecast (3a). The more favorable resource plans were selected based on the present value of societal total costs and resource diversity (3c).

4. Analyze Selected Resource Plans

   Additional Environmental, Technical, and Transmission Analyses (4a), along with an initial Phase of Risk and Uncertainty Analysis (4b), were completed before the Multi-Attribute Decision Rule Analysis (4c) was accomplished. Thirteen base plans were analyzed in the Multi-Attribute Decision Rule Analysis (4d) and a Short List of 13 Resources was published (4e). While the public process (4f) proceeded, MPC computer models were updated with known changes (4g). Because of known updates to such items as the load forecast, off-system sales

price, and critical water hydro peaking capabilities, a second Risk and Uncertainty Analysis (Phase 2) was completed (4h). The results of all analyses were used to develop a Resource Negotiation Action Plan (4i) that identified resources in order of preference.

5. Select Best Plan and Best Resources

   The Resource Negotiation Action Plan was used to develop the preliminary integrated least cost resource plan (5a). Detailed in-house discussions and contract negotiations (5b) are ongoing and may modify the *1993 Load Forecast and Integrated Least Cost Resource Plan* (5c) and MPC's action plan (5d).

MPC's need for resource was defined by the base case load forecast identified in the *1992 Load Forecast and Integrated Least Cost Resource Plan*. Whenever the load forecast exceeds existing and committed resource capability, MPC has a need for additional resources. MPC's base case forecast need for resource in 1996, before the addition of future supply-side or demand-side resources alternatives, is 47 average MW energy and 152 MW peak. By the year 2001, the need for resources increases to 105 average MW energy and 436 MW peak. This is shown in Illustration 3 in Appendix A. (The 1993 load forecast, which was not available until mid-1992, was included in the Phase 2 Risk and Uncertainty Analysis.)

Illustration 4 in Appendix A, displays the surplus or deficiency resource balances after low cost demand-side conservation is considered. The deficiency numbers, represented as negative numbers, indicate that MPC must acquire this amount of resources. For example, the need for additional resources in the year 2001 is 12 average MW of energy and 320 MW of peak. This need assumes that the quantity and cost of future demand-side resources are acquired as forecasted. The amount of demand-side resources in Illustration 4 in Appendix A, represents the quantity selected in the *1992 Load Forecast and Integrated Least Cost Resource Plan.*

MPC's ILCP process included an evaluation of load forecast resources, and resource plans. The 1992 base case load forecast, before the inclusion of demand-side resources, has a 1.6% compound annual growth rate for peak. Beyond 1996, MPC has a much greater need for peak or capacity resource than baseload energy resource.

MPC's ILCP includes MPC existing resources; contracts for future resources in place prior to the ILCP process; upgrades to MPC hydro facilities; MPC demand-side program; a life optimization on a thermal plant; a seasonal exchange; a winter purchase; and optional resources. The resources and their status are described in Section 7.0 "MPC's Integrated Least Cost Resource Plan."

Additional activities that will influence future MPC integrated least cost resource plans are described below:

1. In November 1992, MPC filed an application with the Federal Energy Regulatory Commission (FERC) to relicense 9 of its 14 hydroelectric facilities on the

Missouri and Madison rivers. The Missouri-Madison Hydroelectric Relicensing Project, better known as the Project 2188 Relicensing, involves 8 hydroelectric sites at Madison, Hauser, Holter, Black Eagle, Rainbow, Cochrane, Ryan, and Morony dams, and one nongenerating site at Hebgen Dam. The current license expires in 1994.

2. The MPSC adopted integrated least cost resource planning guidelines in December 1992.

3. Congress recently passed the Energy Policy Act which will significantly affect the utility industry. MPC will incorporate the Energy Policy Act into the ILCP as appropriate.

4. Continue the collaborative effort with CLCPAC and public involvement.

5. Input from MPC's Business Plan and analysis from other departments are important ingredients to the resource planning process.

Technical backup and workpapers on the integrated least cost planning process are available in MPC's *1993 Load Forecast and Integrated Least Cost Resource Plan Technical Appendix*.

2.0 LOAD FORECAST

The following sections outline the process and results of MPC's 1993 Load Forecast. More detailed information can be found in the *1993 Technical Appendix*, which includes detailed input and output data as well as model specifications.

2.1 Process Overview

Historical annual sales data, in MW hours at the customer's meter, are gathered for five major classes: (1) Residential Class; (2) Commercial Class; (3) Industrial Class; (4) Contract Industrial Class; and (5) Other Class. The Other Class includes various lighting, interdepartmental, rural electric cooperatives (RECs), and irrigation customers. Explanatory variables, or the inputs, that may influence annual sales or electricity consumption are collected for historic and forecast time periods. These variables include population, income, the price of electricity, the percentage of electric space heat customers, weather variables, an industrial production index, number of customers, and the price of other fuels. Internal, state, and national sources are used to develop both the historical and forecast values of the explanatory variables.

The annual sales forecast for the five major classes is developed through several techniques. Three of the customer class sales (Residential, Commercial, and Industrial) are modeled through econometric and statistical models. That is, the relationship between consumption and the explanatory variables is estimated in the form of a mathematical or regression equation. These models state that one or more of the explanatory variables are related to consumption. Contract Industrial Class sales estimates are determined through individual customer questionnaires and professional judgement. Other Class sales estimates are determined by trend, judgement, and a mathematical relationship with the Residential and Commercial classes.

The annual forecast sales for each major class are added together to develop MPC's total sales at the customer's meter. Annual losses (that is, the energy lost in the operation of MPC's electric system) are added to sales to develop the annual energy load representing MPC's resource responsibility. To determine annual losses, an equation is used in which historic load is a function of total and off-system sales. Annual energy load is shaped to monthly loads through the use of seasonal regression equations and historical trends that account for the affects of normal monthly weather on customer electrical usage. Finally, monthly peak is computed from monthly energy with the annual peak being the highest of the monthly peaks.

The development of the base case load forecast is described in the *1992 Load Forecast and Integrated Least Cost Resource Plan* and in *Volume 1 - 1992 Load Forecast Technical Appendix*. The energy load, peak load, and sales by large class from 1991 through 2015 for the base load forecast, are shown in

Illustration 5 in Appendix A. The 1992 load forecast was used in the ILCP process that defined the base plans which identified the Short List of Resources. The 1993 load forecast, which became available in the fall of 1992, was included in the Phase 2 Risk and Uncertainty Analysis on load.

2.2 Base Case Results

The results of the forecast process are shown on Illustration 6 in Appendix A. The historical data spans the years 1960 - 1991, and the forecast is for 1992 - 2016. The forecast, before demand-side resource activities, drops Residential Class sales from a historic growth rate of 4.0% (4.8 average MW per year) to 1.6% (4.1 average MW per year). This lower growth rate can be attributed to stabilizing percentages of electrically heated homes and more efficient appliances. The sale of electricity in the Commercial Class, which has historically experienced rapid growth at 5.5% (6.0 average MW per year), is expected to maintain a strong growth of approximately 2.0% (5.5 average MW per year). Recent trends indicate continued strong growth in the number of customers in the Commercial Class.

The Industrial Class sales are forecast to grow at a rate of 2.3% annually (2.6 average MW per year), as compared to a historical rate of 3.4% (1.8 average MW per year). The forecast growth is higher than that experienced historically in terms of average MW per year, and is due in part to increased optimism in the economy. The Contract Industrial Class sales, or large industrials, are expected to show minimal growth throughout the forecast. The slow growth is shown by a 1.9% (3.5 average MW per year) historical growth rate dropping to 0.4% (1.1 average MW per year) for the forecast period. Finally, the Other Class growth rate is expected to drop from a historical growth rate of 3.0% (1.6 average MW per year) to a 1.1% (1.0 average MW per year) forecast rate. Irrigation sales are forecast to remain stable; lighting is forecast to decline; and the RECs are forecast to increase slightly.

Total sales, energy, and peak load are all forecast to grow at about 1.5% compounded annually, or 14.4 average MW, 16.3 average MW, and 25.8 MW per year respectively. This is in contrast to historical growth rates of approximately 3%, which translates to total sales of 17.3 average MW, energy at 19.1 average MW, and peak at 26.4 MW per year historically. Energy loads are shown in Illustration 7 and peak loads in Illustration 8 (both illustrations are in Appendix A). The historical and forecast base case monthly and annual energy and peak load are listed on Illustration 9 in Appendix A.

2.3 Alternative Growth Scenarios

High and low cases are included with the base case forecast in Illustrations 6, 7, and 8 in Appendix A. These alternative growth scenarios are developed from

optimistic and pessimistic input assumptions that forge the forecast. Alternative growth scenarios bracket the base case and provide a range of possible futures. These scenarios are used in the ILCP process to test the risk due to uncertainty in future load growth. The high case assumes a return to vigorous historical growth rates of input variables. The low case assumes very minimal growth of input variables and the loss of 3 of the 16 Contract Industrial customers around the year 2000.

The alternative growth scenarios are also used to develop a probability analysis to deal with the risk and uncertainty inherent in the forecast process. From the analysis, the base case was assigned a 59% probability of occurrence. The high and low cases were assigned probabilities of 20% and 21% respectively.

3.0 FIRM OUT-OF-STATE SALES

Current utility out-of-state sales include firm sales to PacifiCorp, Black Hills Power and Light, Washington Water Power, and the Bonneville Power Administration. Firm utility sales are identified on Illustration 10 in Appendix A. These sales were possible due to MPC's short-term energy surplus condition. These firm out-of-state sales are added to the forecast loads to develop total resource responsibility. For resource planning purposes, these out-of-state sales are not supplied by long-term resources. MPC only acquires long-term resources for its native load. As shown in Illustration 10 in Appendix A, these sales end on or before April 1996.

The PacifiCorp Sale represents a six-year firm utility obligation that started in January 1990; it will end in December 1995. The sale involves 15 MW of peak and energy through 1992, then 10 MW of peak and energy through 1995. The PacifiCorp Sale resulted from the settlement of MPC's negotiations in connection with the Pacific Power and Light Company and the Utah Power and Light Company merger.

Black Hills Power and Light Sale is a low load factor sale that started in June 1989; it will end in September 1993. In April 1992, the obligation changed from 25 MW peak to 30 MW peak.

The Washington Water Power Sale (WWP) is an off peak sale of 36 average MW of firm energy until December 1993, then 26 average MW of firm energy from January 1994 to December 1994. The contract ends in December 1994.

The Bonneville Power Administration (BPA) sale is a firm energy commitment for the operating years 1993-94, 1994-95, and 1995-96. The sale is for 467,000 MW hours of firm energy (no capacity) for each operating year. Deliveries will be made during the months of September through April. The rate of delivery during these months will be approximately 80 average MW.

4.0 EXISTING AND FUTURE RESOURCES

This section describes MPC's existing resources and identifies possible future resources. It should be noted that the Corporation's share of Colstrip Unit No. 4, is a non-MPSC regulated resource that has been sold under long-term contract to the Los Angeles Department of Water and Power and Puget Sound Power and Light, is not considered as a future resource to serve MPC customers.

4.1 Existing Supply-side Resources

MPC's existing resources include thermal, hydroelectric, utility contracts, and interruptible load. These resources are described in more detail below.

4.1.1 Thermal Resources

MPC's existing utility thermal resources include the J.E. Corette Plant, Colstrip Units No. 1, 2, and 3, Lake Diesel-Yellowstone National Park, and Old Faithful Diesel-Yellowstone National Park. The number of units, commercial operation dates, peak capability, annual energy, fuel, nameplate ratings, and ownership of these resources are outlined in Illustration 11 in Appendix A.

The total annual energy output for the J.E. Corette Plant and MPC's share of the Colstrip thermal units is 557 average MW. The January peak capability for the thermal units is 697 MW. These energy and peak capabilities are based on actual historical performance of the plants accepted by the MPSC.

MPC's thermal units will be affected by the Clean Air Act. The severity of this impact on individual plants is not known although the impacts are not expected to be significant relative to industry impacts. When the regulations become firm and when the SO_2 credits assigned to each plant are final, a more definite assessment for each plant can be made. MPC does not have any Phase 1 plants. Phase 1 plants are plants that must comply with certain requirements of the Clean Air Act by 1995.

Also, MPC will continue to monitor the Billings air quality. The air quality may or may not impact the J.E. Corette Plant. Currently, the necessary information to access the impact on J.E. Corette Plant is not available.

4.1.2 Hydroelectric Resources

MPC's hydroelectric system consists of 14 individual projects; 13 have generating facilities. The projects range in size from 1 MW to 168 MW of total installed nameplate capacity. Approximately 40% of MPC's installed hydro capacity lies west of the Continental Divide at Thompson Falls, Kerr, Milltown, and Flint Creek dams. The remaining 60% of the system capacity lies east of the Continental Divide and includes Mystic, Madison, Hauser, Holter, Black Eagle, Rainbow, Cochrane, Ryan, and Morony dams. Hebgen Dam, located on the Madison River, is used as a storage facility. (MPC's hydroelectric system also benefits from water storage in the U.S. Bureau of Reclamation's Canyon Ferry and Hungry Horse projects.) Illustration 12 in Appendix A, identifies the number of units, the year installed, the January peak capability used in the Resource Planning Analysis, the critical water peak used in the final plan, the annual critical water energy, and the nameplate rating for these resources.

The *Hydroelectric Capability Study* that MPC completed in 1990 addressed the energy and peak capability of MPC's existing hydroelectric system. MPC utilized the historical water record and actual production to determine energy and peak capability. The results of this study determined a hydroelectric annual average water energy capability of 385 average annual MW and a January peak capability of 489 MW. This is a reduction of 15 average MW energy and 31 MW January peak from previous planning capabilities. The Montana Public Service Commission has accepted the 385 average annual MW energy value. MPC's critical water energy value is 335 average annual MW and is unchanged from previous plans. The results of the 1990 study were used in the ILCP Analysis. (See Boxes 1a through 3a in Illustration 2 in Appendix A.) As a result of the hydroelectric relicensing efforts and how MPC plans to run its hydro facilities in the future, MPC's critical water peak was revised from 489 MW to 435 MW; this is shown in Illustration 12 in Appendix A. The new critical water peak number was factored into the ILCP process during the Phase 2 Risk and Uncertainty Analysis (Box 4h of Illustration 2 in Appendix A). A discussion on the hydro critical peak numbers is included in Section 6.5.2.

The hydro facilities are licensed by the Federal Energy Regulatory Commission (FERC). MPC's license to operate the Missouri-Madison Hydroelectric Project (FERC Project No. 2188), which includes the Hebgen, Madison, Hauser, Holter, Black Eagle, Rainbow, Cochrane, Ryan, and Morony developments, expires in November 1994. After three plus years of study and extensive public and agency consultation, MPC filed an application for relicensing with FERC in November 1992. MPC anticipates that FERC will make a decision on the application before the end of 1994.

In the application, MPC proposed improvements at the Madison, Hauser, and Rainbow developments. The electrical and mechanical equipment in the Madison and Hauser powerhouses will be replaced with modern equipment in 1995-1996 and 1998-2000, respectively. These improvements will enable MPC to generate more electricity using the same amount of water. The January peak and installed capacity will increase by 2.0 MW and 3.8 MW at Madison and 3.0 MW and 4.5 MW at Hauser respectively.

The improvements proposed at Rainbow will be completed in 1996-1997. A new powerhouse is planned as well as an increase in the hydraulic capacity of the plant. The improvements will result in an increase in January peak and installed capacity of 7 MW and 23 MW respectively. Once the Rainbow powerhouse is rebuilt, Cochrane Reservoir can be operated at the level for which it was originally designed. This operating change will add 5.3 MW of installed capacity to Cochrane.

An expansion at the Ryan Plant was also proposed in the Project No. 2188 Relicensing Application and is considered to be a future resource; this will be contingent upon the results of the ILCP and FERC processes. In addition, MPC has identified an upgrade at the Thompson Falls plant as a future resource. Both of these future resources are discussed in Section 4.4.1.

On July 17, 1985, FERC granted MPC and the Confederated Salish and Kootenai Tribes a 50-year joint license for the Kerr Project (FERC Project No. 0005). As part of a settlement between MPC and the Tribes, it was agreed that MPC will operate Kerr for the first 30 years of the license and the Tribes will operate it for the remaining 20 years. It was also agreed that MPC would train tribal members to operate the Kerr Project beginning in 2010 until the Tribes take over the plant and operations in 2015. In addition, the FERC license stipulated that MPC must develop a fish and wildlife mitigation plan. This plan was submitted to FERC in June 1990, and is currently being reviewed.

MPC's license to operate the Flint Creek Project (FERC Project No. 1473) expired in July 1988. MPC elected not to renew the license. In May 1992, FERC accepted MPC's surrender of the license and granted a new license to operate the project to Granite County. Granite County has asked FERC to reconsider certain portions of its licensing order. A decision on the County's motion for reconsideration is pending. Flint Creek has been off-line since October 1989. However, contingent upon the FERC license, Granite County anticipates that the Flint Creek Project will be expanded to 2.5 MW of generating capacity, and MPC will probably purchase the output.

MPC's license to operate the Milltown Hydroelectric Project (FERC Project No. 2543) was extended in 1990 from December 1993 until

December 1999. The license was extended so the relicensing would more closely coincide with the Environmental Protection Agency's decision on the Milltown Superfund Site. MPC anticipates proposing improvements to the Milltown power generating equipment if it files an application for a new license. The preliminary evaluation indicated that generating capacity at the plant could be increased by 1 MW by adding modern generating equipment.

The FERC license for the Mystic Project (FERC Project No. 2301) expires in December 2009. At this time, MPC has no plans to increase the generating capacity at Project No. 2301.

4.1.3 Utility Contracts

MPC's utility contract resources include purchases from Washington Public Power Supply System (WNP No. 1), the Idaho Power Company and Basin Electric Power Cooperative, and power exchanges with BPA, and Idaho Power Company (see Illustration 13 in Appendix A). (The Qualifying Facility (QF) resources shown in Illustration 13 in Appendix A, are discussed in Section 4.3.)

Under the WNP No. 1 contract, MPC purchases 79 MW of capacity and 67 average MW of energy from BPA. This purchase is delivered to MPC through its interconnections with BPA. This contract expires in June 1996; it is not renewable.

The Idaho Power Company purchase is a seasonally differentiated firm power purchase ending in March 1996. MPC receives 75 MW of energy and peak in the winter months (October through March) and 25 MW of energy and peak in the summer months (April through September) from Idaho Power Company. This contract is not renewable beyond 1996.

Basin Electric Power Cooperative will make surplus energy available to MPC from April 1, 1993 through March 31, 1995. MPC will purchase a minimum of 427,000 MW hours during each of the contract years, with a maximum rate of delivery of 75 MW per hour.

The BPA Peak for Energy Exchange contract provides 100 MW of capacity. All energy received must be returned to BPA within seven days with a 29 average MW energy payment. This contract expires in June 2001. Renewal of this contract was outside of the Request For Proposal (RFP) window of 1995-2000. It is possible that this contract could be extended beyond 2001; however, MPC has no knowledge of the terms or conditions of such a contract extension. In the ILCP process, MPC assumed an extension of this contract under existing contract terms. MPC

will continue to look at contract renewal as a possible future resource to be included in MPC's next RFP.

The Idaho Power Company seasonal exchange contract specifies that MPC will receive 50 MW of energy and capacity from Idaho Power Company for 90 days during the winter. In return, MPC delivers 50 MW of capacity with an average of 75 MW of energy for 60 days during the summer to Idaho Power Company. This contract ends December 1997; however, there is a possibility of extending this contract. This is discussed in Section 4.7.1.

4.1.4 Interruptible Load

MPC currently has 64 MW of interruptible load from a single source; Rhone-Poulenc Basic Chemicals. (See Illustration 13 in Appendix A.) In the studies which identified the Short List of Resources, the interruptible load was included annually (see Box 4e of Illustration 2 in Appendix A). This was consistent with the way interruptible load was handled in the March 1992 base case plan. In mid-1992, discussions with Rhone-Poulenc suggested that MPC would not serve Rhone-Poulenc as a firm load beyond 1995. This uncertainty was included in Phase 2 of the Risk and Uncertainty Analysis on load forecast and resource capability (Box 4h of Illustration 2 in Appendix A); it is also reflected in the selected resource plan.

4.2 Existing Demand-side Resources

The existing demand-side resources refer to the resources already acquired. The resources outlined in this section are embedded in the load forecast. Therefore, the current load forecast would be higher if demand-side resources had not been in place. From 1987 through year end 1992, MPC has acquired demand-side resources totaling 8.9 average MW annual energy (without losses) and 17.0 MW of peak (noncoincident and without losses). These demand-side resources were acquired through the following programs:

Program	Energy	Peak
Super Good Cents	2.3%	5.7%
Free Weatherization	11.9%	0.0%
Efficiency Plus Audits (R)	12.0%	0.0%
Efficiency Plus Lighting (R)	4.0%	12.7%
Efficiency Plus Business Partners	35.9%	43.7%
Leased Lighting Conversions	22.8%	25.6%
Efficiency Plus Ground Srce Ht Pumps	0.5%	1.5%
Efficiency Plus Audits (C)	0.4%	0.7%
Efficiency Plus Lighting (C)	9.9%	9.9%
Efficiency Plus Electric Motor Rebate	0.4%	0.3%
TOTAL	100.00%	100.0%

The demand-side resources MPC plans to acquire in the future are outlined in Section 4.5.1.

4.3 Qualifying Facilities Resources

Qualifying Facility (QF) resources are defined as resources that qualify under the *Title 18, Code of Federal Regulations* and the applicable *Administrative Rules of Montana*. The *Administrative Rules of Montana* state that "... utilities should implement competitive solicitations ... before acquiring any new resources." The all source competitive bid includes QF resources.

Existing qualifying facilities include Broadwater Dam, Montana One, Billings Generation, Inc. (BGI), and various small QFs. Existing Qfs will account for 38 average MW of energy and 45 MW of peak in 1993. In mid-1995, the QF resources will increase by 47 average MW of energy and 52 MW of peak when Billings Generation, Inc. begins commercial operation (see Illustration 13 in Appendix A). Illustration 14 in Appendix A, displays the total expected peak and energy from the existing QF contracts from operating year 1993-1994 to 2002-2003 for hydro, wind, thermal, and total.

The Broadwater Dam project, which became commercial in June 1989, is a 10 MW nominally rated hydroelectric facility located on the Missouri River near

Toston, Montana. The project is owned and operated by the Montana Department of Natural Resources and Conservation.

Montana One, a 35 MW contract capacity facility, officially known as the Colstrip Energy Limited Partnership, began commercial operation in May 1990. This facility is located 6 miles north of MPC's Colstrip generating complex and is operated by Ultrapower-Constellation Operating Services (UCOS).

On March 1, 1991, MPC signed a long-term contract with Billings Generation, Inc. (BGI), with an expected commercial date of July 1994. This thermal plant will be located adjacent to the existing Exxon Refinery in Billings, Montana. The facility will burn petroleum coke, a waste product of Exxon's refinery process, in a fluidized bed boiler. In addition to generating power, BGI will provide steam to Exxon. The 42 MW and the July 1994 in-service date was the information available at the time resources were analyzed. The result of continued contract discussions has increased the peak capability to 52 MW and the in-service date has been updated to June 1995. This newest information was incorporated into the selected resource plan.

4.4 Future MPC Supply-side Resources

The Clean Air Act deals with SO_2, NO_x, and air toxins. Consequently, it will have an impact on future thermal resources. However, the impact on individual plants is not known at this time. MPC will continue to monitor the affects of the Clean Air Act on possible future resources.

4.4.1 Hydroelectric Resources

Nondiscretionary rehabilitations are required at the Rainbow, Madison, Hauser, and Milltown facilities. Rehabilitation at these four MPC hydro plants is necessary and considered nondiscretionary due to safety-related items, age, relicensing efforts, or obsolescence. "Nondiscretionary" means that to ensure continued operation at these plants, MPC believes that the rehabilitation work should progress as planned. These are rehabilitations; not additions. Capacity increases will result from the installation of modern, more efficient equipment. However, Rainbow will be rehabilitated with increased hydraulic capacity.

Two additions to existing plants are considered discretionary. "Discretionary" means that MPC has some flexibility and choice as to when the additions can be made. For planning purposes, MPC assumed these resources had flexibility beyond constraints of the FERC license to ensure that the right resource was timed at the right time. The Thompson Falls Project (FERC Project No. 1869) license was due to expire in December 2015. In April 1990, FERC amended MPC's Thompson Falls

license from a 40-year term to a 50-year term to extend the license expiration date to 2025 and to include the addition of 41 MW of January peak and 50 MW of installed capacity. MPC requested a two-year extension from FERC to extend the commercial operation date to April 29, 1996. Construction of the new powerhouse is scheduled in 1994-1996. Improvements at Thompson Falls were evaluated in the ILCP process.

The 40 MW installed capacity upgrade at Ryan was included in MPC's Application for a New License for the Missouri-Madison Hydroelectric Project, which was submitted to the Federal Energy Regulatory Commission in November 1992. A new powerhouse would be added and the hydraulic capacity of the plant would be increased. With the new upgrade, Ryan will be operated as a peaking plant rather than as a run-of-river plant. With Cochrane and Morony, as an integral part of the Ryan peaking operation, MPC would realize an incremental increase of January capacity of 43 MW.

4.4.2 F.W. Bird Plant

MPC's F.W. Bird Plant is located in Billings, Montana. MPC's interpretation of recent environmental legislation suggests that an environmental assessment of the Billings area may be required before life optimization can take place. Environmental regulations indicate that even though the facility is an existing facility that has not been operated for many years, the F.W. Bird Plant may fall under new resource guidelines. Under these assumptions, the earliest on-line date is 1997 due to the time necessary to complete an environmental assessment.

Two scenarios of operation were considered for this plant: peaking and hydro firming. These two life optimization possibilities would have different costs, operating characteristics, and length of life.

The peaking operation could include full capacity operation 24 hours per day during two months in the summer (July and August) and up to four weeks during the winter season. This scenario would have a 15-year life.

The hydro firming operation could allow operation of the plant as a baseload unit for up to 11 months of the year. During low water flow years, the plant would be used to generate the difference in energy between actual hydro production and that produced by hydro production in average water flow years. Hydro firming capital costs are $13,960,000 more than the 15-year life peaking operation scenario. This hydro firming operation would have a 30-year life.

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The 40 MW installed capacity upgrade at Ryan was included in MPC's Application for a New License for the Missouri-Madison Hydroelectric Project, which was submitted to the Federal Energy Regulatory Commission in November 1992. A new powerhouse would be added and the hydraulic capacity of the plant would be increased. With the new upgrade, Ryan will be operated as a peaking plant rather than as a run-of-river plant. With Cochrane and Morony, as an integral part of the Ryan peaking operation, MPC would realize an incremental increase of January capacity of 43 MW.

4.4.2 F.W. Bird Plant

MPC's F.W. Bird Plant is located in Billings, Montana. MPC's interpretation of recent environmental legislation suggests that an environmental assessment of the Billings area may be required before life optimization can take place. Environmental regulations indicate that even though the facility is an existing facility that has not been operated for many years, the F.W. Bird Plant may fall under new resource guidelines. Under these assumptions, the earliest on-line date is 1997 due to the time necessary to complete an environmental assessment.

Two scenarios of operation were considered for this plant: peaking and hydro firming. These two life optimization possibilities would have different costs, operating characteristics, and length of life.

The peaking operation could include full capacity operation 24 hours per day during two months in the summer (July and August) and up to four weeks during the winter season. This scenario would have a 15-year life.

The hydro firming operation could allow operation of the plant as a baseload unit for up to 11 months of the year. During low water flow years, the plant would be used to generate the difference in energy between actual hydro production and that produced by hydro production in average water flow years. Hydro firming capital costs are $13,960,000 more than the 15-year life peaking operation scenario. This hydro firming operation would have a 30-year life.

4.4.3 J.E. Corette Plant

MPC is currently reviewing programs that may be necessary to accommodate the continued operation of the J.E. Corette Plant beyond the end of its book life in late 2004. In the ILCP process continued operation of this resource was assumed.

The 1990 Clean Air Act Phase II requirements will affect the J.E. Corette Plant. MPC is currently studying options that will allow MPC to operate this facility in compliance with those requirements. MPC does not believe meeting compliance requirements will be an obstacle.

4.5 Efficiency Improvement Resources

4.5.1 Future MPC Demand-side Resources

Three MPC DSM program scenarios were included in the resource stack for development of the *1993 Load Forecast and Integrated Least Cost Resource Plan*. These program scenarios, along with others, were developed in 1991. The 1991 development led to what was used in 1992 to create this resource plan. The MPC demand-side resources development activities over the last two years are summarized below.

1991 DSM Resource Development

In 1991, MPC developed ten possible demand-side resources program scenarios through the use of templates. A template is a spreadsheet that ties specific program information (i.e., savings per end use) and load information (i.e., number of customers) together with assumptions of possible penetration rates, customer costs, estimated cost of promotion, and incentives to calculate DSM energy and peak savings on a 20-year cycle. Demand-side resources program scenarios were developed for four classes of customers: Residential, Commercial, Small Industrial, and Contract Industrial. Within each of the four classes, standard and accelerated acquisition rates were developed. The standard acquisition rate is made up of a basic set of assumptions about program characteristics, including annual penetration rates, levels of promotional costs, incentive values, and manpower. The accelerated acquisition rate is a modified set of program assumptions including higher manpower, higher promotional costs, higher incentive levels, and higher annual penetration rates. The accelerated programs acquire approximately the same amount of energy and peak as the standard programs, only in a shorter amount of time.

By combining the demand-side programs, resource portfolios consisting of one program from Residential, Commercial, Industrial, and Contract Industrial classes were created. MPC's 1991 ILCP process resulted in the selection of the demand-side portfolio consisting of Standard residential, Accelerated commercial, Standard industrial, and Accelerated contract industrial (SASA). The SASA level of demand-side resources acquisition is shown in the *1992 MPC Load Forecast and Integrated Least Cost Resource Plan*.

The demand-side resources programs were developed from demand-side measures with a maximum cost of 115% of MPC's avoided cost rates. This 15% advantage to marginal demand-side measures was recommended by MPC's Conservation and Least Cost Planning Advisory Committee and included in the ILCP rules of the *Administrative Rules of Montana* which were finalized by the Montana Public Service Commission in December 1992. The demand-side measures were packaged into programs with average costs substantially less than the avoided costs.

1992 DSM Resource Development

The demand-side resources used in the 1992 planning process were an extension of the 1991 demand-side resources described above. During the 1992 process, three demand-side portfolios were reviewed: SASA, SSSS, AAAA. The three portfolios represent the slowest (SSSS), the fastest (AAAA), and a middle (SASA) acquisition rate. Illustration 15 in Appendix A, outlines these three portfolios. MPC focused on the SASA demand-side resources and identified similar resource plans using the SSSS and AAAA demand-side resources alternatives. The resulting information from using the three portfolios to create various resource plans was applied to address the uncertainties of DSM quantity and price and to understand the supply-side resource flexibility necessary to accommodate all cost-effective demand-side resources. MPC is committed to adjust the resource plan to accommodate all cost-effective demand-side resources.

4.5.2 Transmission and Distribution (T&D) Improvements

This resource will be comprised of a number of projects that improve the efficiency of the transmission and/or distribution systems. These projects include, but are not limited to, voltage conversion, conductor replacement, replacement of transformers with lower loss units, and shifting loads to other circuits or substations.

For many years, MPC has considered efficiency improvements in evaluating the economic viability of transmission and distribution projects. However, no systematic effort was undertaken to identify projects that are

economically viable based solely on improved efficiency of the transmission and/or distribution system. This resource will be further developed by identifying and implementing such projects and will be evaluated using MPC's ILCP process.

Since this project has just begun, the magnitudes of the capacity and energy components of this resource are not known at this time. However, a rough estimate for these projects is 12 MW and 6 average MW by 2003.

4.6 RFP Resources

As a result of the *1992 Load Forecast and Integrated Least Cost Resource Plan*, MPC identified a need for future resources starting in the mid-1990s. This need was filled by MPC resources and resources of undefined ownership. To expand the resource base to ensure all appropriate resources were considered in the ILCP process, MPC published a Request For Proposal (RFP) for resources in an all-source competitive bid released in July 1991. The competitive bid solicitation process followed the recommendations of the Conservation and Least Cost Planning Advisory Committee and MPC's understanding of the proposed guidelines of the Montana Public Service Commission.

The RFP process identified 76 projects that represent about 5,500 MW. These are listed below.

No. of Proposals Received	Type of Project Received
3	Demand-side and large industrial generation projects
33	Natural gas projects representing about half of total capacity offered
4	Coal/coal gas projects
7	Waste coal projects
1	Petroleum coke project
3	Geothermal projects
7	Hydro projects (including pumped hydro)
13	Wind projects
5	Existing utility proposals

Costs of energy for the 76 projects range between 34.7 and 118.4 mills/kWh (levelized 1991 $'s). The lives of the various resources ranged from 9 years to 36 years. Of the 76 projects, 48 of them are in the state of Montana. The remaining 28 out-of-state projects consist of the following: 4 from Wyoming, 13 from Washington, 3 from Nevada, 1 from North Dakota, 1 from Utah, 3 from Idaho, 2 from Oregon, and 1 from Colorado.

The demand-side and large industrial projects are located in Montana. The largest project life is 16 years.

Of the 33 natural gas projects, 17 are located in Montana; 12 in Washington; 2 in Oregon; 1 in Nevada; and 1 in Idaho. Project life ranges from 9 years to 30 years. The size varies from 8 MW to 220 MW of peak capacity and from 5 average MW to 201 average MW of energy.

Of the four coal/coal gas projects, two are located in Montana; one in Utah; and one in Wyoming. The project life varies from 16 to 30 years. One of the four bids was rejected early in the process because of lack of data. The size of the remaining three units ranges from 108 MW to 161 MW of peak capacity and from 44 average MW to 141 average MW of energy. Three of the projects are considered baseload projects, and one is a co-generation project.

Six of the seven waste coal projects are located in Montana. The project life varies from 25 to 35 years. The size varies from 40 MW to 92 MW of peak capacity and from 35 average MW to 78 average MW of energy. All seven projects are considered baseload projects.

The one petroleum coke project is located in Montana; it is a co-generation project with a 30-year life.

All three geothermal projects are located outside of Montana (two in Nevada and one in Idaho). Project life varies from 20 to 30 years. Project size varies from 20 MW to 22 MW of peak capacity and 12 average MW to 18 average MW of energy.

The seven hydro projects include five operating run-of-river and two pumped hydro projects. Five projects are located in Montana, one is located in Idaho, and another is located in Wyoming. The project life varies from 20 to 35 years. Project size varies from .1 MW to 250 MW of peak capacity and .8 average MW to 103 average MW of energy.

Of the 13 wind proposals, 12 are located in Montana, and 1 is located in Wyoming. Resource life varies from 25 to 36 years. Project size varies from 4 MW to 52 MW of peak capacity and from 2 average MW to 25 average MW of energy. One of the proposals was rejected due to lack of significant data.

The five existing utility proposals are located in Montana, North Dakota, Colorado, Washington, and Utah. Resource life ranges from 10 to 20 years. Size varies from 98 MW to 114 MW of peak capacity and from 30 average MW to 86 average MW of energy. One of the out-of-state proposals withdrew from the process in February 1992.

For general descriptions or definitions for pulverized coal, combustion turbine, combined cycle, integrated gasification combined cycle, pumped hydro, wind, or geothermal technology, see the Glossary.

4.7 Other Western Region Utility Resources

This section describes resources that were not bid into the RFP but that are available to MPC.

4.7.1 Existing Contracts

MPC's two current exchange contracts are the Idaho Power Co. Exchange, which ends in 1997; and the BPA Exchange, which ends in 2001. MPC believes that both exchanges can be extended. The Idaho Power Company provided information regarding extension of the existing exchange. This exchange was evaluated using the ILCP process. Terms and conditions of the BPA Exchange are not known. In our resource planning analyses the BPA Exchange contract was extended using existing contract terms. Current contract terms of the Idaho Power Company and BPA exchanges are discussed in Section 4.1.3.

The Idaho Exchange was evaluated under two options: one was to extend the existing exchange under conditions similar to the current contract terms; the second was an extension with a 26 MW increase in the size of the exchange. The Idaho Exchange was evaluated in a manner consistent with all other future resources.

The end of the BPA exchange is outside the window of development (1995 - 2000) targeted by the RFP and other resources evaluated using the ILCP process. Therefore, for the purpose of this study, it was extended with current contract conditions and terms, realizing that the terms of a future extension could be different.

4.7.2 Potential Contracts

Arizona Public Service (APS) is a potential short-term seasonal exchange contract from June 1, 1996, until at least February 28, 1999. MPC would receive 50 MW of capacity and 12.5 average MW of energy during the

winter period of November 1 through February 28. APS would receive 25 average MW of energy during each summer period of June 1 through September 30. This contract was evaluated in the Static Analysis of the ILCP process, but was moved out of the Dynamic Analysis because of its short-term nature. MPC continues to evaluate this resource as an option to address uncertainty.

4.8 Alternative Resources

MPC recognizes that the alternative resources discussed below may affect the resource plan and will be evaluated in the context of the ILCP rules. However, these resources, other than wind and geothermal, were not included in the ILCP process. MPC also recognizes that although the wind and geothermal resources included in the RFP process were not competitive, it is possible that these resources may affect our resource plan in the future. The 1992 Energy Policy Act identified certain tax credits for alternative resources that may enable them to be more competitive in the future.

4.8.1 Wind

MPC recognizes there is potential for wind resource development and is interested in fully understanding this as a potential future resource. The 1992 Energy Policy Act may improve the economic competitiveness of wind resources. Therefore, MPC will continue to monitor developments in this resource area and undertake studies to further understand wind as a potential resource.

4.8.2 Geothermal

Although MPC received geothermal resource bids through the RFP process, they were not competitive. However, the tax credits allowed through the 1992 Energy Policy Act may make this resource more competitive in the future.

4.8.3 Billings MHD Plant - J.E. Corette Plant Site

This nonutility project would consist of a stand-alone Magnetohydrodynamics (MHD) plant adjacent to the existing J.E. Corette Plant. The Magnetohydrodynamics Development Corporation (MDC) is developing a project for potential Department of Energy (DOE) Clean Coal Technology (CCT) cost share funding. MPC supports this project because MHD has the potential to be the most cost-effective way to burn coal with the least impact on the environment. The state of Montana and

numerous Montana communities also support this project. This is demonstrated by letters of endorsement from the communities, $25 million dollars of coal tax reserve funds set aside by the state of Montana, and a local tax exemption worth $25 million dollars over the life of the plant. The future of this project is unknown since it is dependent upon the competitive selection in 1993 for the government/industry co-funding.

If selected, the MHD plant would share the J.E. Corette Plant site, the coal handling facilities, and the transmission facilities. The net output would be about 80 MW of electricity. Production would consist of two phases: a 3-year demonstration phase (1997 - 1999), and a 15-year plus (2000 - on) baseload operation. Firm power production can start as early as 1998. Adding the MHD plant to the site not only would add 80 MW of electric capacity, but would also reduce the total site SO_2 emissions by the J.E. Corette Plant and MHD coal pile management.

As an Independent Power Producer (IPP), the Magnetohydrodynamics Development Corporation propose to sell its power to MPC and other northwest utilities. It is anticipated that 30 MW of the MHD capacity could be utilized to meet part of MPC's needs after consideration in the context of the ILCP rules.

4.8.4 Other Alternative Supply-side Resources

There was not sufficient information to complete a Comprehensive Analysis on the alternative resources discussed below. However, MPC will continue to monitor their development, and modify the resource plan as appropriate.

4.8.4.1 Solar

The current solar resource development has high capital costs and low conversion efficiencies; consequently, large, utility-grade solar resources are not viable in Montana. MPC recognizes the continued improvement in cost and efficiencies.

Also, the MPC service area receives considerably less solar energy than other areas of the country during the winter months when the electrical production is needed. Some smaller, dispersed applications of photovoltaic may be considered in a planning cycle in the future. The 1992 Energy Policy Act, along with improvements in conversion efficiencies, should spur further development of solar resources.

4.8.4.2 Fuel Cells

Fuel cells convert the chemical energy in a fuel gas to DC electricity. Conceptually, they are similar to a battery with a continuous addition of chemical energy; natural gas is the preferred fuel at this time.

A considerable amount of research and development is underway with respect to fuel cells and demonstration fuel cell projects have been completed. Larger size units are expected to be commercially available in the mid-1990s.

Fuel cells create a significant amount of heat during operation, therefore, siting will be affected by the availability of fuel supply and hosts to consume the waste heat.

4.8.4.3 Fuel Switching

Fuel switching is the replacement of electric space and water heating with natural gas heat or other fuel. Given current projections of electric and gas marginal cost, and considering capital costs, it appears that fuel switching may be economical and improve fuel efficiency. MPC has made an initial review of this concept as an electric resource and will continue to explore fuel switching as a possible future resource.

5.0 PUBLIC INPUT AND UTILITY MANAGEMENT REVIEW

MPC's ILCP process included input from many sources. MPC used this input to ensure the ILCP process accounted for utility and nonutility information and concerns.

5.1 Conservation and Least Cost Planning Advisory Committee (CLCPAC)

MPC's ILCP process has been developed over the years through a collaborative effort with MPC's Conservation and Least Cost Planning Advisory Committee (CLCPAC). The CLCPAC was formed in 1988 through an agreement between MPC, the Natural Resources Defense Council, and the District XI Human Resource Council. The CLCPAC is comprised of individuals or groups who are interested in energy policy and the utility regulatory process in Montana. Members include representatives from MPC, the District XI Human Resource Council, the MPC Large Users Group, the Montana Environmental Information Center, the Northern Plains Resource Council, the Montana Department of Natural Resources and Conservation, and the Northwest Power Planning Council. The purpose of the CLCPAC was to create a voluntary, informal, collaborative forum in which to develop a shared understanding of MPC's conservation and resource planning and acquisition processes and to provide recommendations for improving them. MPC modeled its ILCP process after the recommendations outlined in the *Integrated Least Cost Planning Report and Recommendations to Montana Power Company and Montana Public Service Commission.*

As MPC developed the ILCP process for the *1993 Load Forecast and Integrated Least Cost Resource Plan*, MPC met with the CLCPAC to present an outline of the ILCP process and to request their input.

MPC met with the CLCPAC on April 30, 1992 and presented the same information that was presented to the MPC Utility Officers on April 23, 1992. The purpose of this meeting was to outline and describe the proposed methods to be used throughout the ILCP process and to ask for comments and guidance in developing the ILCP process. The results of this meeting caused MPC to evaluate alternative environmental impacts.

On September 14, 1992, information that had been presented to the MPC Utility Officers on August 6 and August 25, 1992 was presented to the CLCPAC. The purpose of this meeting was to outline the results of the various analyses completed to date and to outline the resources and resource plans analyzed through the Risk and Uncertainty and the Decision Rule Analyses. The result of this meeting caused MPC to expand its Phase 2 Risk and Uncertainty Analysis.

5.2 Montana Public Service Commission (MPSC)

On December 15, 1992, the Montana Public Service Commission (MPSC) adopted new rules establishing policy guidelines on integrated least cost resource planning for electric utilities in Montana. These guidelines were based, in part, on the CLCPAC publication entitled *Integrated Least Cost Planning Report and Recommendations to Montana Power Company and Montana Public Service Commission*, which was published in October 1990. The process MPSC followed to produce the new rules included meetings and roundtable discussions with other utilities and other interested parties.

The ILCP rules in the *Administrative Rules of Montana* were not finalized until December 1992, which was after MPC had completed the ILCP process. However, based on available drafts, MPC made a concerted effort to incorporate and follow the proposed guidelines, and feels that the plan conforms to the guidelines.

5.3 Public Process

MPC's public process consisted of a bill insert that was sent to every MPC customer during October and November 1992; six public meetings that were held in November 1992; a questionnaire that was handed out at the public meetings; and a second bill insert that was sent to every MPC customer in January 1993. This second bill insert summarized the results of the customer questionnaire and public meetings.

The purpose of the public process was threefold: (1) inform the public of the process by which future resources come into MPC's Resource Plan; (2) receive public input on that process; and (3) discuss the Short List of Resources and receive comments on those resources.

The first bill insert was designed so one side gave basic information outlining MPC's need for resource in the future, the status of MPC's current resources, and the proposed Short List of Resources resulting from the 13 base plans (See Box 4d on Illustration 2 in Appendix A). The other side of the bill insert listed two ways for customers to participate: (1) by completing the questionnaire and indicating how much weight various factors should be given in choosing future resources, and (2) by attending one of the public meetings. A copy of the bill insert is provided in Illustration 16 in Appendix A.

The questionnaire asked customers how they would weigh the following factors: price, environmental impact, resources located in Montana, reliability of service, and local community impact. Space was available for any other factors that customers wanted to add to the list. The customers were asked to weigh each factor as heavy, medium, light, or none.

The total number of questionnaires processed was 3,678, approximately 1.43% of MPC's customers. The straight customer tally of how customers filled out the questionnaire is shown on Illustration 17 in Appendix A. Reliability and environmental concerns were the two issues that received the highest ratings; price was a close third. The majority of the respondents were city dwellers, who had been Montana residents for over 20 years.

Public meetings were held at the following places on the dates indicated:

Location	Date
Bozeman	November 10, 1992
Butte	November 11, 1992
Helena	November 12, 1992
Great Falls	November 18, 1992
Missoula	November 19, 1992
Billings	November 24, 1992

Average attendance at the public meetings was 25. The public's questions and concerns centered around conservation; cost of future resources; rates and MPC's rate structure; clarification and status of various resource technologies including wind, hydro, natural gas, coal, and MHD; MPC's load forecast; environmental concerns; and using Montana resources for Montanans. The audience's choices for communication between MPC and customers, in order of preference, were bill inserts; public meetings; newspaper advertisements; and newspaper articles. The public expressed an interest in being informed of the results of the public meetings and bill insert questionnaire and in MPC continuing the public process in the future.

The January 1993 issue of *Montana Energy*, which is a monthly bill insert publication, informed MPC customers of the results of the public process and extended MPC's appreciation of their participation (see Illustration 18 in Appendix A).

5.4 Litchfield Consulting Group, Inc. Evaluation

The Litchfield Consulting Group, Inc. (Litchfield) was asked by MPC to evaluate the integrated least cost resource planning process used in developing MPC's ILCP plan. The results of the optimization process were not available during the review by Litchfield. MPC had completed the dynamic portion of the process (refer to Boxes 1a through 3c in Illustration 2 in Appendix A) and was preparing to conduct the analysis for Risk and Uncertainty, additional analyses for

transmission, environmental and technical concerns, and the Multi-Attribute Decision Rule Analysis.

The Litchfield review included examining the process used to evaluate resource proposals, the models used to estimate costs and benefits, and the decision-making process for making recommendations. The results of the Litchfield evaluation included the following paragraph in their report to MPC:

"The bid evaluation process will provide accurate information for decision makers to select new resources. In the final analysis decisions must be based on judgment. This bid evaluation process is designed to provide both quantitative and qualitative information on which to base that judgment. The technical evaluation staff have been careful to not create a process where a "black box" makes decisions without appropriate trade-offs. This resource evaluation process provides MPC management and the MPSC with the information needed in order to make an informed judgment about those resources that can best meet MPC's future energy needs."

5.5 MPC Utility Officer Review

There were five meetings with MPC Utility Officers. Each meeting is discussed below.

1. The material presented to the Utility Officers during the April 23, 1992 meeting, included a description of the Static Analysis, benefit definitions, cost definitions, definition of externalities, methods to account for environmental externalities, MPC's environmental matrix, environmental externality adjustment factor, debt equivalent equity, possible static screening ratios, Static Analysis selection criteria, and Dynamic Analysis selection criteria.

2. A joint meeting with the Utility Officers and the CLCPAC was held on May 20, 1992. At this meeting, Dynamic Analysis; proposed quantifiable Risk and Uncertainty Analysis; proposed nonquantifiable Risk and Uncertainty Analysis; proposed Decision Rule; quantitative analysis on the attributes of the Decision Rule; and the nonqualitative analysis on the attributes of the Decision Rule were discussed.

3. On August 6, 1992 the results of the dynamic process were presented to the Utility Officers . The presentation included an overview of the dynamic process, the bid response and resource list, base resource plans, other analysis summaries, financial comparisons, load and resource tabulations, and visual presentations depicting customer and owner concerns.

4. The meeting on August 25, 1992 covered plan cost; plan surplus or deficiency; customer and owner concerns; and the uncertainty analyses. The uncertainty analyses were done on load, fuel, DSM, economy sales, environmental, transmission, debt equivalent equity, reliability, technical and resource cost. As a result of this meeting, the Short List of Resources was published.

5. In November, the Resource Negotiation Action Plan was presented to the Utility Officers. The Resource Negotiation Action Plan was used to focus the negotiation with all resources and provide the base for the current plan.

6.0 INTEGRATED LEAST COST PLANNING PROCESS

MPC's need for resource in the year 2000 is over 400 MW. The ILCP process was used to screen 84 potential resources (totaling over 5,500 MW) to 13 potential resources (representing over 700 MW), some of which will be used to fill the need in 2000. This section describes the ILCP process that MPC used to identify and evaluate resources and resource plans.

6.1 Determine the Need for Future Resource

A need for future resources exists whenever the difference between the capability of MPC's existing and future committed resources and the load forecast is negative. To determine if there is a need for energy or peak resource, MPC uses the following "need equation:"

$$\textit{Need} = (\Sigma \textit{Resource Capabilities}) - \textit{Load Forecast}$$

As shown in this equation, any change in the load forecast or resource capabilities cause a change in the need. Both of these variables represent a "future forecast." Consequently, MPC's ILCP process accommodates for forecast uncertainty through a thorough Risk and Uncertainty Analysis.

In the 1993 ILCP process, MPC used the base case load forecast from the *1992 Load Forecast and Integrated Least Cost Resource Plan* for the **Load Forecast** variable in the equation and various combinations of existing and potential resources for the sum (Σ) of **Resource Capabilities** in the equation. The hydro resource capabilities were identified using critical water hydro generation capabilities. MPC's forced outage reserve requirements were computed as a percent of load, and the need for peak resource was increased by this amount.

MPC applies the **Need** equation twice: once to identify if a need exists for energy resource, and again to identify if a need exists for peaking resources. MPC identifies a need for energy resource on an annual basis. The need for peaking resource is determined during the forecast peak load month of January.

MPC's surplus and deficiency, identified in the 1992 ILCP, before the addition of future supply-side or demand-side resources, is shown in Illustration 3 in Appendix A. The horizontal line represents load and resource balance. A need for resource exists when either the annual average energy line (box) or the January peak line (+) fall below the horizontal line. A table of MPC's surplus or deficiency is shown at the bottom of Illustration 3 in Appendix A. In 2000, MPC is 108 annual average MW deficient and 413 MW peak resource deficient; consequently, MPC will need to acquire 108 average MW and 413 MW of resource by 2000 to meet our customers' electrical requirements.

After the Decision Rule Analysis was completed, the need for resource changed as additional information became available. There were changes to the critical

water hydro peaking capability, a new base case load forecast was available, there was a possibility of losing a large customer, and there was a possibility of losing an existing contract resource. These changes are described in more detail in Section 6.5.2.

6.2 Identify Resources

Questions arose concerning whether the future resources identified in the *1992 Load Forecast and Integrated Least Cost Resource Plan* were indeed the best least cost resources; consequently, MPC made a concerted effort to identify all potential resources to ensure that the best resources to serve our customers' needs are acquired. This section describes how MPC identified potential resources. A detailed discussion of the resources themselves can be found in Section 4.0. (This step in the ILCP process is displayed as Boxes 1a through 1c in Illustration 2 in Appendix A.)

First, MPC's *1992 Load Forecast and Integrated Least Cost Resource Plan* identified three categories of resources that met our customers' needs into the future. These resources included MPC supply-side resources, MPC demand-side resources, and non-MPC resources; these were included in the ILCP process as resource alternatives. Two additional MPC demand-side resources were added as resource alternatives to identify a lower and upper bound based on rate of acquisition. In addition, rehabilitation of four existing hydro resources is necessary and considered nondiscretionary in the ILCP process because of age, obsolete generators and equipment, or safety-related concerns.

Second, MPC used a bidding process to solicit bids for supply-side and demand-side resources. The RFP was issued in July 1991. The bidders were to submit completed bids to MPC by December 20, 1991. The RFP indicated that the preferred on-line date was within a bid window from July 1, 1995, through June 30, 2000; however, resources with an on-line date prior to the bid window were not eliminated. The RFP solicitation generated responses from 44 project sponsors (76 projects). The 76 projects totaled approximately 5,500 MW.

Third, after the bids had been received, MPC realized information had not been received from some western utilities with known seasonal exchange potential. Consequently, MPC solicited potential resource information from these utilities, and this information was included in the ILCP process.

6.3 Evaluate Individual Resources (Static Analysis of Resources)

The screening methodology and selection criteria used by MPC to evaluate the resources is described below. (This step is shown as Boxes 2a through 2c in Illustration 2 in Appendix A.)

6.3.1 Review Bid Proposals for Completeness

All bids were reviewed to:

1. ensure they complied with the minimum bid requirements,

2. ensure that the information necessary for consistent analysis was included,

3. review cost assumptions for reasonableness,

4. review escalation assumptions and indices specified in the proposals, and

5. place all bids with indexed bid prices on a consistent basis.

Minimum bid requirements for a supply-side bid included a price bid summary, reliability summary, risk summary, operation summary, environmental summary, and information on cost estimation, financing requirements, dual fuel capabilities, fuel plan, maintenance requirements, performance guarantee, design and engineering, generator design parameters, site acquisition, management plan, thermal host, voltage support, permits and licenses, by product disposal plan, and milestone schedules.

Minimum bid requirements for a demand-side bid included economics on cost estimation, financing, payback, evaluation of cost; reliability information on project location, technology, maintenance, performance, design and engineering; risk associated with site acquisition, design and engineering, and management; and operation information on equipment disposal, contract term, bulk power system, and protection criteria, a price bid summary, risk/reliability summary, operation summary, and environmental summary.

The bids were reviewed to ensure that they complied with the minimum bid requirements and to ensure that the information needed for a consistent analysis was included. If the bid price information was deemed incomplete, the bidder was notified and given a reasonable amount of time in which to respond. At this point, three bids were found to be inadequate and were not evaluated further.

Also, as it would not be prudent for MPC to pursue bids that could not ultimately be developed at the prices bid, the cost assumptions were reviewed for reasonableness and compared to average industry costs. Bidders were again given a reasonable amount of time in which to respond

to questions or requests for additional information arising from this comparison.

For bids that specified bid price escalation indexes, the index assumptions were reviewed for consistency, applicability, and reasonableness. Some bids assumed very little escalation and others assumed high escalation. To compare the bids equally, MPC removed assumed escalation indices from the bid prices and replaced them with "like" indices from the Data Resources Incorporated (DRI) publication used in MPC's resource plan escalation assumptions. Assumptions consistent with MPC 's resource plan fuel escalation assumptions were used in place of the nonfixed fuel related bid prices. The replacement assumptions ensured fair and consistent treatment of all bids in the selection process. Also by bench marking all resources (bids, MPC, and other western utilities) to a common set of escalation assumptions, any bias due to escalation assumptions was removed by placing all resources on a level playing field.

6.3.2 Screen Resources

6.3.2.1 Phase 1 Screening

After the completeness review, a first screening of the resources was completed. The bid price and the estimated environmental impact supplied by the resource sponsors were used in the first screening to rank the resources. Two ratios were developed for each resource.

$$Ratio\,1 = \frac{B}{C} = \frac{Resource\,Benefit}{Resource Cost}$$

$$Ratio\,2 = \frac{B}{C}\,x\,\frac{Loss Adjustment\,Factor}{Environmental\,Externality Adjustment\,Factor}$$

Ratio 1, a benefit to cost ratio, was computed as the ratio of the system benefit of the project to the cost of the project. The benefit of the project over its life is the product of MPC's March 1992 avoided cost rates times the project's energy (firm and nonfirm) and peak quantities delivered to the electric system. The project's energy and peak capabilities and avoided cost rates were differentiated by winter and summer seasons. In theory, the avoided cost rates represent the cost of marginal resource in MPC's resource plan. The cost was the bid price supplied by the project's resource sponsor. Resources with the larger benefit to cost value provide the most benefit to the electric system.

Ratio 2 multiplies the benefit to cost ratio by a Loss Adjustment Factor (LAF) and divides this result by an Environmental Externality Adjustment Factor (EEAF). The loss adjustment factor was 1.056 for resources determined to reduce line losses and 1.00 for all other resources. The EEAF used in this equation was supplied by the resource sponsor. Each resource sponsor's bid package included a table that provided a generic EEAF for various resources. The EEAF could range from 1.00 or less for an environmentally benign resource to 1.15 or greater for an environmentally harsh resource. MPC's review of the bid price and environmental impacts for each resource continued through both phases of the screening process.

The Ratio 1 and 2 results are displayed in Illustrations 19 and 20 in Appendix A, respectively. Each "box" depicts a resource levelized annual cost in millions of dollars on the x axis, and the ratio value on the y axis. These illustrations show that the resource annual cost, which is dependent upon the size of the resource, ranges from about $1 million per year to about $100 million per year. The ratio values range from slightly greater than 0.4 to about 2.4. Theoretically, resources with a low annual cost and large ratio value would be the most preferred.

Selection Criteria

Resources that passed Phase 1 of the screening process were selected based on the following criteria.

1. Ratio 1 and 2 values were computed for each resource.

2. Resources were ranked by Ratio value. Resources with a Ratio 2 value greater or equal to the RFP demand-side resources bid were passed.

3. The RFP demand-side resources was passed.

4. Resources with special operating characteristics, which were not captured by the ratio value, were passed.

5. Since MPC's greatest need is for peak resource, "pure" peaking resources were passed.

6. The Ratio 1 values were checked to insure that using ratio 2 values represented a reasonable set of the best resources.

7. The selected resources were reviewed to insure that a significant number of sizes, technology types, operating characteristics, and fuel types were passed.

Results

Forty-three resources were passed and are represented on Illustrations 19 and 20 in Appendix A, by the boxes containing an "X". These resources can be classified in the following manner:

Total Number of Resources Passed	Resource Classification
35	RFP supply-side resources.
2	Demand-side resources; one MPC and one RFP sponsored.
5	MPC supply-side resources.
1	Other utility resource.

Resources that did not pass Phase 1 of the screening process were placed on an alternative list. MPC's selection process was fluid enough to allow resources that were placed on an alternative list to be returned to active analysis status should circumstances warrant.

6.3.2.2 Phase 2 Screening

The 43 resources that passed Phase 1 and two additional MPC demand-side resources were included in Phase 2 of the screening process. The results of the environmental, technical, and transmission analyses were incorporated into the Phase 2 screening. The purpose of Phase 2 was to reduce the number of resources on the active analysis list through a more detailed qualitative and quantitative analysis of the resources. The quantitative analysis included evaluating the cost of the resource, environmental externality adjustment factor, line loss adjustment, and debt equivalent of purchase power. The qualitative analysis included a review of the technical feasibility, transmission and distribution interconnection, socioeconomic benefits, dispatch benefits, siting benefits and risks, and fuel supply. The results of the qualitative analysis were factored into the selection criteria.

To complete the quantitative analysis, four new screen ratios were computed. These screening ratios, or "R" ratios, were used to identify the resources that would be passed to the next step of the ILCP process. The following "R" ratios were computed for each resource.

$$R1 = \frac{Resource\,Benefit * LAF \;+\; Dispatch\,Benefit}{Resource\,Cost}$$

$$R2 = \frac{Resource\,Benefit * LAF \;+\; Dispatch\,Benefit}{Resource\,Cost \;+\; DEE}$$

$$R3 = \frac{Resource\,Benefit * LAF \;+\; Dispatch\,Benefit}{Resource\,Cost * EEAF \;+\; DEE}$$

$$R4 = \frac{Resource\,Benefit * LAF \;+\; Dispatch\,Benefit}{Resource\,Cost * EEAF}$$

Where:	LAF =	Loss Adjustment Factor
	EEAF =	Environmental Externality Adjustment Factor
	DEE =	Debt Equivalent Equity of Purchased Power

The remainder of this section describes each parameter of the four "R" ratios. The Selection Criteria described below explains how these ratios were used to select the resources to be passed to the next step in the ILCP process.

The **Resource Benefit** is the benefit of the project over its life is the product of MPC's avoided cost rates times the project's energy (firm and nonfirm) and peak quantities delivered to the electric system. The project's energy and peak capabilities and avoided cost rates were differentiated by winter and summer seasons. Any additional benefit associated with the resource was also considered. (This is the same as Phase I).

The **Line Adjustment Factor (LAF)** was determined by MPC and applied to those projects that could decrease line losses as a result of the project. The LAF was the same as Phase 1, but it

also included information from a Transmission Analysis. The Transmission Analysis is described in Section 6.3.2.5. With the exception of the demand-side resources, all resources were assigned a LAF of 1.00.

The **Dispatch Benefit** for each resource was computed as the product of the amount of MW hours of dispatchable energy and a dispatch value; it is shown in the following equation:

$$\mathit{Dispatch\,Benefit} = \mathit{MWh\,Dispatch} \ * \ \mathit{Dispatch\,Value}$$

The amount of dispatchable energy was provided by the resource sponsors. The dispatch value (mills/kWh) was computed as the difference between the dispatch rate (i.e. variable production cost in mills/kWh) provided by the resource sponsor and the mills/kWh value of the resource being displaced. Generally, the dispatch rate provided by the resource sponsors was extremely low, implying limited opportunity to displace the resource with a lower cost resource. In most cases, the resources would only have the opportunity for displacement during the spring runoff, when regional hydro surplus is available at a very low rate.

The **Resource Cost** was reviewed by MPC and, if appropriate, adjusted to consistent indices. If the resource sponsor provided a fixed bid price over time, no adjustment was made. However, if the resource sponsor provided a price that varied over time with economic conditions, an adjustment to a common indexing source was made. This adjustment was necessary to avoid bias due to escalation assumptions. MPC used the summer 1991 DRI publication for purposes of indexing.

The **Environmental Externality Adjustment Factor (EEAF)** supplied by the resource sponsor was reviewed by MPC and, if appropriate, adjusted to conform to MPC's understanding of the environmental externality impacts. MPC's EEAF for each resource was developed from resource specific environmental information and accounts for environmental impacts remaining after environmental controls and mitigation were implemented. The EEAF ranged from a value of 1.00 or less for a resource with little or no remaining environmental impact to 1.15 or more for a resource that could have significant environmental impacts. See Section 6.3.2.3, for a detailed discussion of development of the EEAF.

The **Debt Equivalent Equity (DEE)** for all purchased power resources was computed. Financial rating agencies have recently adjusted utilities capital structures to account for the debt-like risk

associated with purchased power contracts. The imputed debt adjustment varies by the perceived risk associated with each contract. The DEE is MPC's method to account for this financial consideration on the utility's capital structure and cost of capital. The following equation was used to estimate MPC's DEE:

$$DEE = \frac{(TPV\,Fixed\,Pmt \;*\; Risk\,Factor) * Wei\,Equity\,\%}{Before\,Tax\,Factor}$$

The **Total Present Value (TPV)** of the purchased power contract **Fixed Payment** is multiplied by a perceived **Risk Factor**. It is possible for the risk factor to vary from 0% for no risk contracts up to 80% or more for some take-or-pay contracts. MPC assumed that all of the purchased power contracts will be viewed as low risk since MPC will not pay unless power is actually delivered, therefore, a 20% factor was used. Contracts with no fixed payment are also evaluated by the rating agencies, and in the analysis, MPC used half of the TPV energy payment as the **TPV Fixed Pmt** in the equation. The **Wei Equity %** represents MPC's weighted equity percent component of the weighted cost of capital. The denominator of this equation, **Before Tax Factor**, puts the DEE in terms of a pre-tax revenue requirement dollar figure.

Selection Criteria

The following selection criteria was used in Phase 2 of the screening process.

1. Analyze and rank the resources using the "R3" ratio.

2. Use "R1", "R2", and "R4" ratios to understand risk.

3. If possible, limit the total number of resources passed to the Dynamic Analysis to no greater than 12.

4. If possible, identify a diverse set of resources that represent a mix of operation type, technology, resource sponsor, and fuel type.

5. Attempt to identify resources of various sizes, commercial operation dates, and term of contract.

6. If possible, minimize potential risk (i.e. fuel, transmission siting, environmental permitting, SO_2 allowances, etc.) and avoid shifting risk to MPC via the price bid.

7. To the extent appropriate, consider other benefits and costs associated with the project.

In applying the selection criteria, each resource was analyzed on many attributes, including "R" ratios, cost, EEAF, positive and negative concerns (transmission interconnections, fuel, siting, price risk, etc.), technology, and socioeconomic impact. Next, the top 12 resources, using the "R3" ratio, were identified. A review of the top 12 resources revealed that the desired diversity described by the criteria had not been met. To fully satisfy the selection criteria, 21 resources were passed to the Dynamic Analysis.

As an added test, MPC recomputed the "R3" ratio using the alternate EEAF (i.e. New York adder described in Section 6.3.2.3). The recomputed "R3" ratio was compared to the original "R3" ratio to see if another set of resources would have been selected. Due to the desire to pass a diverse set of fuel types to the Dynamic Analysis, these results showed that the same resources would have been passed.

Results

After evaluating the 43 resources and using the selection criteria described above, 21 resources remained on the active working list. Illustration 21 in Appendix A, displays all resources that were evaluated. Each resource is designated by a "N", "B", "P", or "D"; the resources were either **N**ot passed or were passed as a **B**aseload, **P**eaking or **D**SM resource. This illustration graphs the levelized annual cost of the resource on the x axis and the "R" ratio value on the y axis. The "R3" Ratio Analysis identified a robust set of resources; generally, the same resources were identified using all of the "R" ratios.

Resources that did not remain on the active working list were placed on an alternate resource list. Resources on the alternate resource list could be activated if circumstances warrant it.

The diversity of fuel and operating characteristics are listed below and shown on Illustration 22 in Appendix A.

- 10 Baseload resources
  - 1 - coal gas
  - 2 - coal or coke
  - 3 - natural gas
  - 1 - steam
  - 3 - hydro base

- 8 Peaking resources
  - 1 - surplus power, winter delivery
  - 2 - exchanges
  - 2 - natural gas
  - 3 - hydro
- 3 Demand-side resources

Illustration 23 in Appendix A, displays the results of the Static Analysis in graphical format. The graph displays, as a single point, the capacity cost on the x axis and energy cost on the y axis for each supply-side resource evaluated in the Static Analysis. Resources that passed the Static Analysis are designated by an "O" and the resources on the alternate resource list are designated by an "X". In theory, peaking resources would have low capacity costs and high energy costs and be located nearest the y axis. Baseload resources would have high capacity costs and low energy costs and be located nearest the x axis. The two lines on the graph provide a comparison to the 20-year levelized avoided costs for a peaking resource (20% load factor) and baseload resource (90% load factor). A resource priced at exactly the avoided cost would fall somewhere on this line depending how the total cost of the resource was allocated to energy and capacity costs. As can be seen from the graph, most of the resources that passed the Static Analysis are less costly than the avoided cost resource (i.e. below the lines). Because MPC's selection criteria did not use price as the sole selection criteria, a few resources passed because of other qualities.

6.3.2.3 Environmental Analysis

An environmental committee worked in parallel with the Static Analysis to evaluate each resource's environmental impact and to develop an environmental assessment matrix by which all resources would be evaluated on a uniform and consistent basis. The committee consisted of MPC utility personnel and one person from MPC's Special Resource Management subsidiary. The results of this effort were presented to the CLCPAC.

The environmental review was completed in two parts. The first part was to identify any fatal flaws with respect to the resource's ability to comply with environmental regulations. This high level analysis asked the following questions:

1. Has the resource sponsor reasonably demonstrated an ability to comply with existing water quality standards, solid waste disposal, indoor and/or outdoor air quality, water use standards, land use standards?

2. Has the resource sponsor identified all necessary permits?

3. Has the resource sponsor reasonably addressed compliance with proposed changes to environmental regulations?

4. Has the resource sponsor identified any environmental quantity that would exceed existing and/or proposed environmental regulation?

5. Has the resource sponsor identified any environmental benefit(s) the resource may provide to other processes or the community?

6. Has the resource sponsor included any additional comments or points of interest?

The second part of the environmental review was to develop a more detailed understanding of the environmental externality impacts associated with each project. During this analysis, the committee developed a Resource Environmental Assessment Matrix, then applied this matrix to each resource to develop an environmental index.

The Resource Environmental Assessment Matrix was developed using a Delphi decision making technique. The following issues were identified as environmental concerns addressed by the matrix:

1. Land use

2. Visual aesthetics

3. Global climate

4. Acid rain

5. Smog generation

6. Other emissions to air

7. Solid and liquid wastes

8. Surface/ground water use and quality

9. Outdoor resources

10. Other public concerns

A weight for each of these environmental concerns was developed such that their sum equaled 100%. Each of the environmental concerns was further divided into contributing factors. The contributing factors were assigned a weight such that the sum of the weights equaled the weight assigned to the environmental concern. An example of the Resource Environmental Assessment Matrix for a generic pulverized coal resource is displayed in Illustration 24 in Appendix A. The 2.14 environmental score for the generic pulverized coal resource, located in the upper right-hand corner of the matrix, was computed by first ranking the resource's environmental concerns contributing factor on an environmental impact scale from -4 or less to +4 or more. Each of the impact rankings were then multiplied by the contributing factor weight and summed to equal the score. It should be noted that in Illustration 24 in Appendix A, only the zero or negative environmental impacts (0 to +4 or more) are displayed. A score from -4 or less to 0 represent an environmental benefit.

Using the score from the resource environmental assessment matrix, the EEAF for each resource was indexed to a pre-1990 Clean Air Act generic coal resource environmental impact score of 2.14 by the following formula:

$$EEAF = \frac{Resource\,Envir.Score}{Coal_{pre\text{-}CleanAirAct}\,Envir.Score} * 1.15$$

In 1991, MPC understood the recommendation by MPC's CLCPAC and the initial drafts of the MPSC guidelines that a 15% advantage to be given to demand-side resources. MPC interpreted this recommendation by giving demand-side resources an EEAF of 1.00 and a pre-1990 Clean Air Act coal resource an EEAF of 1.15.

After the EEAF methodology was presented to our CLCPAC, concerns were expressed about the sensitivity of the EEAF to air emissions. Questions were asked on how the EEAF would change if an "adder" approach was used for the air emissions. An "adder" approach is a method that attempts to quantify environmental impacts in terms of mills/kWh and adds that amount to the price of the resource. MPC recomputed the EEAF using New York "adders" for air emissions and the Resource Environmental Assessment Matrix for the remaining environmental impacts. The following table provides an example of how the EEAF might change for different resource technologies.

Technology	MPC EEAF	NY EEAF
N.Gas Combined Cycle	1.044	1.062
Waste Coal, CFBC	1.095	1.176
Pulverized Coal (Post Clean Air Act)	1.082	1.198

The results of this analysis were incorporated into the Static Analysis, Phase 2 Screening of the resources. (See Section 6.3.2.2).

6.3.2.4 Technical Analysis

The Technical Analysis was conducted in parallel with the environmental and transmission analyses. The purpose of the Technical Analysis was to identify any technical problems that were fatal flaws within the resources. This was a high level analysis only. The results were incorporated into the Static Analysis, Phase 2 Screening of the resources. A more detailed Technical Analysis was conducted during the analysis of selected resource plans (see Section 6.5.1).

6.3.2.5 Transmission Analysis

An in-house committee conducted a Transmission Analysis of the resources. The committee work took place in conjunction with the Static Analysis and Dynamic Analysis. The committee reviewed the feasibility and completeness of information provided in regards to MPC's transmission capabilities and system. The committee evaluated RFP, other utility, and MPC resources for such information as increases or decreases in MPC's system losses; transmission interconnection feasibility; review of transmission costs; synchronization concerns; voltage level concerns; impact on the MPC transmission system as a whole; system reinforcement needs; and equipment compatibility. The review took place in two areas: (1) the transmission proposed in each bid resource on the reduced list, and (2) a resource plan's affect on the total system. The committee's findings and concerns were used in the Static Analysis, Phase 2 Screening of the resources and in the Dynamic Analysis.

6.4 Combine Selected Resources into Resource Plans (Dynamic Analysis of Resources)

Unlike the resource-to-resource comparison in the Static Analysis, the Dynamic Analysis compared resource plan against resource plan. A resource plan is some of the working list resources combined with the existing resources that satisfy the requirements of the load forecast. That is, the Need Equation (i.e. Need = (ΣResource Capabilities)-Load Forecast) is satisfied.

This step in the ILCP process is shown as Boxes 3b and 3c in Illustration 2 in Appendix A. MPC's simultaneous optimization of supply-side and demand-side resources uses a computer model (PROVIEW) to build resource plans. A detailed description of the computer modeling and the input assumptions used in the analysis are provided in Appendix B.

The Dynamic Analysis reduced the number of resources from 21 to 13. The first step, a screening step, reduced the number of resources from 21 to 17 by placing four of the resources on the alternative list based on resource plan societal total cost, technical concerns, or removal of duplicate options. The second step reduced the number of resources to 13 (12 supply-side resources and 1 demand-side resource) by recognizing the uncertainty in the amount of cost-effective demand-side resources, by minimization of societal total costs, by short-term customer and owner considerations, and by magnitude of resource plan surpluses. The remainder of this section describes the Dynamic Analysis process in more detail.

6.4.1 Dynamic Analysis Step 1

Due to the number of resources (21) passed by the Static Analysis, it was necessary to further reduce the number of resources to accomplish simultaneous optimization of supply-side and demand-side resources.

After additional analysis two resources were moved to the inactive list (leaving 19 resources). One resource was moved to the inactive list for technical concerns; the second resource, MPC's Thompson Falls run-of-river baseload operation, was moved to the inactive list because the peaking operation was being analyzed as a better match for MPC's need for peak resource.

At least two more resources needed to be moved to the inactive list. These resources were identified by "building" resource plans and analyzing the results. To accomplish this analysis, the following steps were followed:

1. Four of the working list resources were passed directly to Step 2 of the Dynamic Analysis because of their small size or low cost.

The resources in Illustration 25 in Appendix A, that are labeled "MOVED" in the right-hand column represent these resources.

2. The remaining 15 working list resources were used to build 128 resource plans.

The following method was used to analyze the resource plans (128), and identify the most preferred resources.

1. The plans were ranked by the long-term (1991-2030) total present value (TPV) of societal total costs.

2. The resources with the lowest TPV cost plan were identified.

3. The lowest cost plans, which contained the resources that were not included in the lowest TPV cost plan, were identified.

4. Two resources were moved to the alternate resource list.

The table below displays the results of the above analysis. Note the table is in decreasing order of TPV of societal total cost and while the table identifies a single resource, it is not the only resource in the plan.

Plan Nbr	Resource Included	TPV Cost, B$
88	Pulverized Coal	2.542
50	Cogen, Natl Gas CC	2.511
37	Pumped Hydro	2.486
17	Cogen, Coke	2.453
14	CC, Natl Gas	2.449
2	DSM, SASA	2.443
8	F.W. Bird Plant & H_20	2.437
29	CT, Natl Gas	2.422
1	All Remaining	2.420

As a result of this analysis, the pulverized coal and the natural gas co-generation combined cycle units were moved from the working list to the inactive resource list. The 17 remaining working list resources were passed to Step 2 to the Dynamic Analysis.

6.4.2 Dynamic Analysis Step 2

Step 2 of the Dynamic Analysis evaluated the remaining 17 working list resources. As a result of this analysis, 4 of the resources were moved to the inactive list. The remaining 13 resources (12 supply-side and 1 demand-side) are shown on Illustration 26 in Appendix A. The 13 resources are marked "PASSED" in the right hand column.

Demand-side Resources

At the beginning of Step 2, it was recognized that the 3 demand-side resources acquired the same resource over different time periods by using different rates of acquisition.

1. Middle acquisition rate, SASA, 116 MW by 2001

2. High acquisition rate, AAAA, 140 MW by 2001

3. Low acquisition rate, SSSS, 89 MW by 2001

MPC has gained a better understanding of the available demand-side resources over the last several years - but much is still to be learned. There remains uncertainty surrounding the forecasting of the quantity, price, and the rate of acquisition of demand-side resources. MPC's three demand-side resources were developed knowing this uncertainty existed. To address this uncertainty, the SASA demand-side resources was selected to represent the level of demand-side resources available and the uncertainty was tested through the SSSS and AAAA resources. The SSSS and AAAA alternatives were moved to the inactive list and into the Risk and Uncertainty Analysis. In making this decision, MPC recognizes its commitment to pursue the acquisition of all cost-effective demand-side resources that is consistent with needs of the least cost plan and ILCP principles. In the future, should one of the alternate paths (SSSS or AAAA) be more appropriate, MPC will use the ILCP process to adjust the resource plan to accommodate the demand-side resources change.

Selection Criteria

The remaining 15 resources on the working list were analyzed through a dynamic optimization and through evaluating the resource plan results. A selection criteria was required to identify the best resource plans. Illustration 27 in Appendix A, displays MPC's Selection Criteria; a discussion of the criteria follows.

1. The first two criteria pertain to the demand-side resources. The SASA level of acquisition was selected in the manner described above.

2. The third criteria ranks the resource plans on total present value societal total costs. The screening of resource plans by total present value societal total cost is consistent with the MPSC Guidelines on Integrated Least Cost Resource Planning. Later, in MPC's Decision Rule Analysis, other quantifiable and nonquantifiable attributes associated with each resource plan were addressed and used to identify the best resource plan.

3. The fourth criteria strives for a consistent minimum load and resource balance between resource plans. That is, the Need Equation described in Section 6.1 is consistently applied between resource plans.

4. The fifth criteria ensures that a broad range of economic resource combinations are identified within resource plans.

<u>Resource Plans</u>

Resource plans were built from the remaining 15 working list resources using PROVIEW. As the Dynamic Analysis progressed, updated information for MPC's F.W. Bird Plant optimization became available. This information increased the cost of the project and expanded the peaking operation to include a summer baseload operation. Using the updated information for F.W. Bird Plant and the other working list resources, resource plans were built. Significantly different resource plans were identified by applying the selection criteria in the following manner.

1. Rank order plans by TPV of societal total cost.

2. Apply selection criteria 5 to identify significantly different plans.

3. Check each plan to insure selection criteria 4 is satisfied. If the plan fails, proceed through the resource plans until an acceptable plan is identified.

4. Select the lowest cost significantly different plans.

Illustration 28 in Appendix A, displays the ordering by total present value societal total costs of the top 323 resource plans. The 13 diamonds on the line represent the resource plans that were selected to be passed to the Risk and Uncertainty Analysis. Page 2 of this illustration displays statistics for the supply-side resources. For example, Ryan was included

in 60.5% of the resource plans in the 3rd quartile and in 48.9% of the 323 resource plans.

Results

After applying the selection criteria, 13 significantly different resource plans were passed to the Risk and Uncertainty Analysis. Illustration 29 in Appendix A, displays these resource plans. Note that the dollar figures shown in this illustration represent incremental revenue requirements and not societal total costs. Incremental revenue requirements include existing unit fuel, operation and maintenance expenses, plus future new unit revenue requirements, including the recognition for debt equivalent equity.

As a result of this analysis, the pumped hydro and the combustion turbine resources were moved to the inactive list. The pumped hydro was moved to the inactive list because of economics. Two dynamic optimization studies were completed using the pumped hydro resource and all of the working list resources. The first study was conducted before the changes to MPC's F.W. Bird Plant life optimization, and the second was conducted after the changes were received. Both studies suggested that the pumped hydro resource was not the best alternative for MPC in the 1996-2000 time period. Illustration 30 in Appendix A, displays the differences in societal total costs between the final 13 resource plans and the best plan which included the pumped hydro (Plan 111). Careful consideration was given to the dynamic operating benefits estimated by the resource sponsor before moving a resource to the inactive list. As displayed in Illustration 30 in Appendix A, Plan 111 is approximately $7.9 million per year (for 40 years), more costly than the lowest cost resource plan.

The combustion turbine resource was moved to the inactive list because it did not appear in any of the lowest cost resource plans. In the Phase 2 Risk and Uncertainty Analysis, the combustion turbine resource was returned to the working list for further evaluation.

6.4.3 Dynamic Analysis Results

As a result of the Dynamic Analysis, 13 resource plans were passed to the Risk and Uncertainty Analysis. Illustration 29 in Appendix A, displays the 13 resource plans.

Illustration 31 in Appendix A, displays the results of the Dynamic Analysis in graphical format. The graph displays, as a single point, the capacity cost on the x axis and energy cost on the y axis for each of the 18 supply-side resource evaluated in the Dynamic Analysis. The 12 supply-side resources that passed the Dynamic Analysis are designated by

an "0" and the 6 supply-side resources placed on the alternate resource list are designated by an "X". The two lines on the graph provide a comparison to the 20-year levelized avoided costs for a peaking resource (20% load factor) and baseload resource (90% load factor). A resource priced at exactly the avoided cost would fall somewhere on this line depending on how the total cost of the resource was allocated to energy and capacity costs. As can be seen from the graph, the resources that passed the Dynamic Analysis cost no more than the avoided cost resource.

6.5 Analyze Selected Resource Plans

6.5.1 Additional Environmental and Technical Analysis

Additional environmental and technical evaluations were done for the environmental and technical aspects on the resources and resource plans that passed the Dynamic Analysis. The purpose of the additional evaluations was to determine if there were any environmental or technical aspects of a resource that had not been previously identified that could pose problems with permitting, operation, availability, reliability or resource life.

Environmental Analysis

The environmental evaluation included the following concerns:

1. Have the proposed environmental control methods/technologies been proven commercially?

2. Can the consumption/emissions values supplied be expected for this type of resource with the control methods/technologies proposed?

3. If any opinions have been rendered by consultants concerning the environmental impacts of a resource, are they believable and are they defensible in a permitting process?

4. Will a site visit be required to better understand a resource in the context of the surrounding environment?

5. Will any significant opposition to a resource based on its environmental characteristics be expected from the surrounding community during a permitting process?

6. Are there any known or probable environmental mitigation costs for a resource that the resource sponsor has not identified that MPC could be exposed to?

Technical Analysis

The supply-side resources selected from the Dynamic Analysis received additional evaluation of their technical characteristics. The purpose of this evaluation was to determine if any technical aspects of a resource that have not been previously identified could pose either permitting and/or operational problems.

The technical evaluation included the following concerns:

1. Is there significant risk with the proposed generation technology for the type of operation proposed with respect to availability, reliability, or expected life?

2. Is there any single component of the resource with a high probability of failure which, if it failed, could significantly shorten the life of or terminate the resource?

3. What will be the exposure if the primary fuel for the resource becomes unavailable for an extended period of time, e.g., sixty days?

The initial review by the Technical Committee found all plans technically sound with some resources having minor technical aspects that could contribute to risk and uncertainty.

Results

The results of the expanded Environmental and Technical Analysis was passed to the Risk and Uncertainty Analysis. None of the working list resources were moved to the alternate resource list as a result of the additional analysis.

6.5.2 Risk and Uncertainty Analysis

MPC completed a thorough Risk and Uncertainty Analysis on the resources and resource plans passed by the Dynamic Analysis. The Risk and Uncertainty Analysis was conducted in two phases. (This step in the ILCP process is represented in Boxes 4b and 4h in Illustration 2 in Appendix A).

Phase 1

Phase 1 of the Risk and Uncertainty Analysis was extremely comprehensive and included quantifiable and nonquantifiable analysis of the resources and resource plans. Phase 1 of the Risk and Uncertainty Analysis addressed the following 14 uncertainties.

1. Load Uncertainty
2. Fuel Uncertainty
3. Demand-side Resources Cost vs. Quantity Uncertainty
4. Economy Sales Uncertainty
5. Environmental Uncertainty
6. Transmission Uncertainty
7. Plan Debt Equivalent Equity Uncertainty
8. Reliability Uncertainty
9. Technical Uncertainty
10. Resource Cost Uncertainty
11. EEAF Magnitude Uncertainty
12. Demand-side Resources (SSSS and AAAA) Uncertainty
13. No Debt Equivalent Equity Uncertainty
14. Expected Water Plan Uncertainty

Analysis Method and Modeling Assumptions

Each of the 13 resource plans were rerun through PROSCREEN II to quantify the uncertainty described above. MPC quantified customer information such as rates and revenue requirements and owner information such as return of equity and interest coverage ratio. To insure representative values were computed from the models, each run was made without the EEAF applied to the cost and with the DEE included.

In addition, all of the Phase 1 Analysis used expected value production costs in determining revenue requirements. The expected value of production costs were developed by running the production costing model three times, each with different energy available from the hydro resources. The three sets of results were then multiplied by their water condition probability of occurrence to get the expected value of the production costs. The probability of occurrence was developed from 75 years of water data.

Water Condition	Avg. MW Energy	Probability
Poor	335	12%
Average	385	76%
Good	425	12%

Results

A summary of the results of each uncertainty is described in the introduction of Appendix C. Appendix C also includes more extensive information and various graphs on the analysis of the 14 uncertainties. The information presented in Appendix C was included in the Decision Rule Analysis.

Phase 2

After the Decision Rule Analysis was complete, a new load forecast became available; the off-system sales price forecast was updated; the new critical water hydro peaking capabilities became known; and the development of a future resource was questioned. This additional information was significant enough to perform a second Risk and Uncertainty Analysis. The purpose of Phase 2 Risk and Uncertainty Analysis was to either confirm or revise the results of the Decision Rule Analysis (Section 6.5.3). The results of the Phase 2 Analysis were included in the development of the Resource Negotiation Action Plan (Section 6.5.4). The following additional sources of uncertainty were analyzed.

1. New base case load forecast
2. Modified low load forecast
3. High load forecast
4. Removal of a large load as a firm customer
5. Billings Generation Inc uncertainty
6. Existing hydro critical water peak capability

Each of these sources of uncertainty are described below.

New Base Case Load Forecast

In late August the new base case load forecast became available. Up to this time, the 1992 base case load forecast had been used. The new load forecast is described in Section 2.0 of this document. The 1993 energy load forecast is higher than the 1992 load forecast while the 1993 peak load forecast is lower than the 1992 forecast. Illustration 32 in Appendix A, displays these differences. A graph of these two base case forecasts appear in Illustration 33 in Appendix A, along with other load forecast uncertainties.

Modified Low Load Forecast

A modified low load forecast was analyzed to understand the changes to the resource plan should a lower than base case forecast develop. The analysis used an annual growth rate of approximately 0.7% per year which is about half the base case forecast growth rate.

This analysis did not use the low load forecast as published in the *1992 Load Forecast and Integrated Least Cost Plan* because no resource decisions would have been made until after the year 2000. The low forecast has several large customers leaving the system which causes a reduction from current loads. It takes about a decade before the load forecast returns to current load levels.

High Load Forecast

The high load forecast was taken from the 1992 load forecast.

Removal Of A Large Load As A Firm Customer

In mid-1992 it became apparent that MPC's largest load may not be a firm requirements customer after 1996. This customer, Rhone-Poulenc Basic Chemicals Company, is MPC's only interruptible customer. MPC wanted to understand the risk associated with this uncertainty.

Billings Generation Inc Uncertainty

Billings Generation Inc. (BGI) is a QF resource which is expected to come on-line in 1995. MPC has a contract to purchase the output of the BGI facility. During 1992, numerous contract discussions with BGI were held; MPC wanted to understand the consequences if BGI did not come on line as anticipated.

Existing Hydro Critical Water Peak Capability

Historically, MPC's January hydroelectric peak capability was the same as the average peak capability of 489 MW. As a result of the hydroelectric relicensing effort for MPC's Missouri and Madison hydro facilities, it was realized that the future critical water January peak capability should be 435 MW. The exact critical water January peak capability will not be known until the hydro studies are complete. However, MPC anticipates the final result to be within ± 10 MW of the 435 MW capability. The new critical water hydro January peak capability was not known at the beginning of the ILCP process; however, it was included in Phase 2 of the Risk and Uncertainty Analysis.

Off-System Sales Forecast Update

In addition to analyzing the above noted uncertainties, MPC also updated the off-system sales price forecast. The most significant change in inputs was a reduction in the natural gas price forecast escalation from approximately 7% to 5%. The result is a lower off-system sale forecast. The summary of the 1993 off-system sales forecast is outlined in Illustration 34 in Appendix A.

Analysis Method

In establishing the analysis method of the Phase 2 study, MPC made use of the results of the Decision Rule Analysis and Risk & Uncertainty Phase 1 Analysis. The method was to rerun PROVIEW for the various sources of uncertainty using the 11 of the supply-side working list resources (including various alternative) and a combustion turbine resource "activated" from the inactive list of resources.

Two resources, a small hydro project and Stone Container Corp. 38 MW project were not included in the runs. The small hydro facility (5 MW) was not included in the computer runs because it represents less than one year of load growth and is best evaluated outside the models as an option resource. As a result of the Decision Rule Analysis, the large project at Stone Container Corp (38 MW) was not included in the runs. The SASA demand-side resources was fixed into the plans because of its low cost. Illustration 35 in Appendix A, displays the first year available for the various resources used in this analysis.

Modeling Assumptions

The primary purpose of Phase 2 Risk and Uncertainty Analysis was to verify that the preferred resource plan identified by the Decision Rule Analysis was still valid. Since alternative resource plans were being built, the same assumptions that were used in the Dynamic Analysis (displayed

in Appendix B, Computer Modeling Methodology) were used. The exceptions to this were the changes to the load forecast and specific resources being tested.

Results

The results of the Phase 2 Risk and Uncertainty Analysis are displayed in Illustration 36 in Appendix A. The first page identifies the best resource plans from each of the uncertainty runs, which are displayed on pages 2 through 12 of the Illustration. For example, column A on page 1 displays the lowest TPV of societal total cost plan with RPChem and BGI included (i.e. "W/RP&BGI"). Column A can be linked to page 2 through the run number (e.g. "RUN #") 5A. The 5A run number appears in column A, page 1, and in the upper left hand corner on page 2 as Plan 5A. All columns can be linked in this manner with the exception of column E.

Column E was derived by combining column F with the results of the Decision Rule Analysis. The Decision Rule Analysis selected plan 28, shown in the far left column, as the preferred plan. The modified resource plan, shown in column F, was run through the models to compute TPV of societal total costs shown in the bottom table. The modified plan provided a lower cost plan than column F.

On page 2, Plan 5A, two identical plans are shown in columns J and K with the only exception being in 1997 when one plan has Ryan and the second plan has a combustion turbine (CT). Comparing the 1991-2030 TPV of societal total costs for these two plans show that Ryan and a CT provide nearly equivalent long-term TPV of societal total costs. This information was used to justify the replacement of the CT with Ryan when resource plans were transferred to page 1.

In developing the resource plans, Ryan was not allowed to be timed into a plan beyond the year 2000 because of FERC's "2+2" rule. The "2+2" rule states that once a FERC license has been issued, a utility has 2 years to start construction, 2 years to complete the project once started, and a possibility of a 2 year extension of time. Thus, once a license has been issued, a utility has a maximum of 6 years to have the project on-line. MPC assumed that a new license for the 2188 Project would be issued in 1994. However, it is possible that a license would be issued after 1994 or, because of the number of facilities being re-licensed in the 2188 project, the "2+2" rule doesn't strictly apply. MPC has asked FERC to examine the application of the "2+2" rule in light of ILCP principles and the multi-project nature of this relicense. Thus, for resource planning purposes, it is reasonable to assume that an on-line date beyond 2000 is possible.

Conclusion

Examination of the lowest TPV cost plans on page 1 of Illustration 36 in Appendix A, is instructive. This information was used in developing the Resource Negotiation Action Plan (Section 6.5.4). The following information summarizes Illustration 36.

1. Several resources, such as Basin winter power purchase, Idaho Power Company 50 MW exchange, Thompson Falls, and MPC life optimization of the F.W. Bird facility, appear in nearly all resource plans.

2. Several resources move in or out of the resource plan depending upon the assumptions. These resources include Ryan, Stone Container's 15 MW resource, and the additional 26 MW exchange from Idaho Power Company.

6.5.3 Decision Rule Analysis

The Multi-Attribute Decision Rule used to identify the ILCP followed the advice of MPC management and the CLCPAC to provide "raw" data and analysis methodology to facilitate their review of the results. MPC's Multi-Attribute Decision Rule encompasses the Decision Rule Matrix information, Risk and Uncertainty Analysis, and other information and provide the foundation from which the August 1992 recommendations were made. (This step in the ILCP process is displayed as Boxes 4c and 4d in Illustration 2 in Appendix A).

Decision Rule Matrix

The Decision Rule Matrix is shown in Illustration 37 in Appendix A. The major categories shown in the left-hand column of this matrix are resource plan surplus or deficiency, customer concerns, owner concerns, customer and owner concerns, uncertainty, resource plan environmental impact, and resource plan debt equivalent equity (DEE) for purchase power contracts. Across the top of this matrix are the plan numbers (e.g. 2, 2x, etc.). This illustration is cross-referenced to Appendix C. (See column labeled Appendix C Page #.)

Within the body of the decision rule matrix are plans identified by a "1". The "1" represent the Resource Planning Department's preferred plan (or plans) for the given category. For example, on line 2, 1s appear under plans 2X, 28, 56 and 113. On page 8 of Appendix C these four plans are circled on the graph of the surplus or deficiencies in the year 2000. The circled plans represent the group of plans that "best" minimize the annual

energy surplus (x axis) and are near zero deficiency for January peak (y axis). Thus, each of these plans received a 1 for this category.

At the bottom of each major category is a line labeled "SUM" which is the sum of the number of times the plan received 1s in that major category. See line 5 as an example. For each major category, the number of times the resource plan was preferred can be identified and the plan that was preferred <u>most</u> can be identified.

At the bottom of the decision rule matrix are two sum lines, lines 57 and 58. The "TOTAL SUM" on line 57 represent the number of times the plan was preferred (i.e. received 1s within the matrix). The second sum line, "NBR TIMES FIRST", on line 58 represent the number of times that particular plan was preferred <u>most</u>. For example, plan 2s "NBR TIMES FIRST" is 1 and results from the Environmental Impact sum shown on line 50.

<u>Recommendations</u>

The following recommendations were made as a result of the multi-attribute Decision Rule Analysis:

1. Develop a formal electric utility resource action plan.
2. Use Plan 28 in the 1993 business plan.
3. Start detailed discussions with all resource sponsors on the Short List with focus on plan 28 resource sponsors.
4. Continue analysis of the resources and resource plans to insure proper business plan resource selection.
5. Compare the final MPSC least cost planning guidelines to the plan selection process.
6. Insure adequate resource flexibility is obtained through resource options or other means.
7. Acquire all cost-effective demand-side resources.
8. Continue to develop a better understanding of the demand-side resources and adjust the resource plan accordingly.
9. Develop a fuel scenario for MPC's F.W. Bird plant repowering.
10. Develop resolution on demand-side disincentives with MPSC.

11. Obtain an understanding from MPSC if self generation and co-generation should be treated as demand-side resources.

12. Obtain from FERC timing flexibility for the Ryan upgrade.

Shortly after the Decision Rule Analysis was complete, new load and resource information became available. Given the magnitude of these changes, it was apparent that the results of the Decision Rule Analysis needed to be verified. This verification was accomplished through the Phase 2 Risk and Uncertainty Analysis discussed in Section 6.5.2. The information gained from the Decision Rule Analysis and the results of the Phase 2 Risk and Uncertainty Analysis were used to develop the Resource Negotiation Action Plan.

6.5.4 Resource Negotiation Action Plan

The Resource Negotiation Action Plan was developed using information from the Static Analysis, Dynamic Analysis, Phase 1 Risk & Uncertainty Analysis, Decision Rule Analysis, public input, and the Phase 2 Risk & Uncertainty Analysis. This step in the ILCP process is displayed as Box 4i in Illustration 2 in Appendix A. The Resource Negotiation Action Plan displayed in Illustration 38 in Appendix A, developed a proposed negotiation strategy for the 13 resources remaining on the working list of resources. The result of negotiations and further analysis by MPC will determine the resources within the ILCP.

7.0 MPC'S INTEGRATED LEAST COST RESOURCE PLAN

This section discusses the resource tabulations in Illustration 39 in Appendix A, and the status of the potential future resources. MPC believes that this plan fills the MPSC's requirements in the *Administrative Rules of Montana (Utility Division), Subchapter 20, Least Cost Planning - Electric Utility.*

ILCP Tabulations

MPC's Integrated Least Cost Resource Plan is shown on the resource tabulations for energy and peak in Illustration 39 in Appendix A. Several items on these tabulations need to be recognized:

1. MPC is in the process of negotiating with potential resource sponsors and continuing to evaluate its own resources. Through this ongoing process, resources within the plan could be deleted, replaced, or added.

2. Transmission and Distribution (T&D) efficiency improvements to MPC's electrical system are recognized in the resource tabulations even though the T&D data was not available until late 1992. The data to estimate the quantity and cost of the efficiency improvements are in the very early stages of development.

3. A line labeled "Alternative Resources" is shown at the bottom of the resource tabulations in recognition that opportunity exists for these future resources. As more information on these resources becomes available, they may help fill MPC's future need for electricity if they meet ILCP criteria. See Section 4.8.

4. As contract negotiations have moved forward, Billings Generation Inc. (BGI) deliveries to MPC have increased to 52 MW January peak capacity from 42 MW in last year's plan. While this latest development was received too late to be factored into the ILCP process, it is included on the resource tabulations.

5. Rhone-Poulenc Basic Chemicals is MPC's only interruptible resource. Contract negotiations reflect a tentative agreement where Rhone-Poulenc Basic Chemicals will no longer be considered a firm load obligation after mid-1996. See Section 4.1.4. This information was included in the Load Uncertainty Analysis.

Resource Status

MPC's ILCP shown in Illustration 39 in Appendix A, is a combination of existing and future resources to meet our customers' electrical needs. Negotiations and continued evaluations with the future resources may cause changes to the ILCP. The future resources in the ILCP can be divided into two categories: those resources evaluated outside the ILCP process, and those evaluated in the ILCP process.

The first category consists of resources evaluated outside the ILCP process because (1) a contract was in place prior to the ILCP process; (2) the resource is an efficiency improvement and is nondiscretionary because of obsolescence or safety-related improvement; or (3) information was not available in time to be evaluated in the ILCP process. These resources are listed below and shown on Illustration 39 in Appendix A.

1. Transmission & Distribution efficiency improvements

2. Flint Creek hydro facility

3. Madison hydro upgrade

4. Rainbow hydro upgrade

5. Hauser hydro upgrade

6. Milltown hydro upgrade

7. Billings Generation Inc (BGI)

The second category included resources that were evaluated through the ILCP process and were identified in August 1992 as the Short List of Resources. These resources are described below:

1. The resources listed below have been identified as most preferred as a result of the ILCP process, which used a societal total cost perspective and a thorough Risk and Uncertainty Analysis. These resources are most desired when faced with an uncertain load and resource future. Even though these resources are most preferred, their status could change as a result of negotiations or additional evaluations. It should be noted that even if all these resources should be included in the ILCP, additional resource will be needed to meet our customers' need for electricity.

    a. MPC's E+ program.

    b. MPC's life optimization of the F.W. Bird plant with an anticipated on-line date for the 1996-97 winter peak season.

       Negotiations with LS Power Corporation have recognized an offer to equate the cost of LS repowering of the facility to MPC's life optimization of the facility. Because of the short lead time for development and permitting uncertainty, MPC and LS Power Corporation are coordinating current actions such that permits can be obtained for both options. Negotiations are continuing.

    c. The upgrade to Thompson Falls hydro facility; projected to be available in mid-year 1996.

d. A new seasonal exchange with the Idaho Power Company.

The new exchange replaces the existing exchange contract which would have expired in 1997. Contract negotiations for the new exchange contract are proceeding.

e. A winter purchase from Basin Electric Power Cooperative is included in late 1996 pending the outcome of contract negotiations.

2. The resources below have been identified as possible option resources. These resources could be acquired to help meet our customers' need for resource. Again, even though these resources are being considered, their status could change as a result of negotiations or additional evaluation.

a. Ryan Hydroelectric Upgrade

In analyzing load and resource uncertainty, Ryan was timed into the resource plan under high, base, and low case load growth conditions in 1997, 2001, and not timed in, respectively. Ryan's on-line date should be considered flexible at this time. In the relicensing of the Missouri-Madison hydro facilities, MPC has asked FERC for recognition of on-line date flexibility. FERC's decision will not be known for some time.

b. Stone Container Corporation's 15 MW Pressure Reducing Turbine

This resource is similar to a demand-side resources in that it resides on the customer's side of the meter and it modifies the load shape. This is considered an option resource under base or high case load growth conditions. The stakeholder (MPC customers and investors) impacts and risks are being evaluated with contract negotiations depending on the outcome of this evaluation.

3. Several resources remain on the Short List but are in limited negotiation status pending the outcome of other resources on the Short List. These resources received full evaluation through the ILCP process but are not as preferred as other resources because of cost or other impacts. As in the preceding categories, even though these resources are not being actively pursued, their status could change as a result of negotiations or additional evaluation. A listing of these resources follows.

a. Tiber reservoir generation addition of 5 MW

b. Stone Container Corporation's 38 MW combustion turbine

c. Westmoreland's 92 MW combined cycle

MPC also recognizes the potential and desirability for development of alternative resources that have not been evaluated through the ILCP process. These resources may include MHD, fuel switching, wind generation, geothermal generation, fuel cells, and solar generation. MPC intends to continue to follow the development of these resources.

8.0 ACTION PLAN

The following action plan will be used by MPC to implement the ILCP.

1. MPC will continue to acquire through its demand-side (E+) program all cost-effective conservation resources that are consistent with the needs of ILCP and conform to ILCP principles.

2. MPC will continue to negotiate and evaluate the following resources with acquisition of these resources most likely.

    a. Seasonal exchange with Idaho Power Company
    b. Winter Purchase from Basin Electric Power Cooperative
    c. Thompson Falls Hydro facility
    d. F.W. Bird repowering or refurbishment (life optimization)

3. MPC will continue technical discussions with the LS Power Corporation and proceed with negotiations for the proposed repowering of the F.W. Bird facility. Replacing MPC's life optimization (refurbishment as a peaking unit) with repowering is contemplated while implementing a joint permitting strategy for either option to address permitting risk. Thus, the F.W. Bird Plant can be permitted as a peaking facility should that option be chosen.

4. MPC will work with FERC to obtain timing flexibility for the Ryan hydroelectric facility to be included into the resource plan. This timing flexibility will be used to address uncertainty.

5. MPC will continue to evaluate Stone Container Corporations' 15 MW resource. Acquisition of this resource to meet load under base or high case load growth conditions depend on the outcome of further evaluation.

6. MPC will continue to monitor and quantify resources acquired through its E+ acquisition to understand and improve the forecasting of cost-effective conservation resources.

7. MPC will continue to monitor and evaluate alternative resources using MPC's ILCP process.

8. MPC will strive to obtain as much flexibility in resource acquisitions to account for deviations in the need for resource identified in MPC's ILCP.

    a. MPC will strive to obtain as much flexibility in on-line dates, contract terms including termination, and potential re-marketing surplus power should low growth be recognized.

    b. MPC will strive to identify potential short-term resource options that could be exercised if an increased need occurs.

GLOSSARY OF TERMS/DEFINITIONS

AVERAGE MW: AVERAGE MEGAWATT: Equivalent to the energy produced by the continuous operation of one megawatt of capacity over a period of one year. (Equivalent to 8760 megawatt-hours.)

AVERAGE WATER HYDROELECTRIC ENERGY: The annual energy production for MPC's existing hydroelectric system for average water flows is 385 average MW. The energy production capability for average water flows is computed from a 75 year water data base.

AVOIDED COST: An investment guideline describing the value of conservation and generation resource investments in terms of the cost of more expensive resources that would otherwise have to be acquired.

BASELOAD RESOURCES: Baseload electricity generating resources are those generally operated continually except for maintenance and unscheduled outages.

CAPACITY: The maximum power a machine or system can produce or carry under specified conditions. The capacity of generating equipment is generally expressed in kilowatts or megawatts. In terms to transmission lines, capacity refers to the maximum load a line is capable of carrying under specified conditions.

CLCPAC: CONSERVATION AND LEAST COST PLANNING ADVISORY COMMITTEE: Representatives include MPC, District XI Human Resource Council, MPC Large Users Group, Montana Environmental Information Center, Northern Plains Resources Council, Montana Department of Natural Resources and Conservation, and the Northwest Power Planning Council. MPC's CLCPAC meet regularly to review and advise MPC on its electric conservation acquisition program, resource planning process, and other matters.

COGENERATION: The simultaneous production of electricity and useful thermal energy. This is frequently accomplished by the recovery of waste heat from an electric generating plant for use in industrial processes, space or water heating applications. Conversely, cogeneration can be accomplished by using waste heat from industrial processes to power an electricity generator.

COMBINED CYCLE: A generating unit consisting of a combustion turbine driving an electrical generator and a heat recovery steam generator that uses the exhaust from the combustion turbine to heat water to steam. The steam is then used to power a steam turbine that drives an electrical generator. Due to the recovery of waste heat, a combined cycle unit has a higher overall efficiency than a typical steam plant or a simple cycle combustion turbine. These units are also known for their high reliability. Natural gas is usually the primary fuel.

COMBUSTION TURBINE: A combustion turbine consists of an engine (similar to a jet aircraft engine) driving an electrical generator. These units are noted for their low construction costs and short construction times. Generally, they are used for peaking capacity. Fuel is usually natural gas with oil as a backup. Year-round maintenance is a significant consideration

for those units seldom operate.

CRITICAL WATER HYDROELECTRIC ENERGY: The sequence of stream flows in the critical period under which the hydropower system will generate about 335 average MW. The average of the July 1934 through June 1938 water data is used to determine the critical water energy.

CRITICAL WATER PLANNING: Critical water planning refers to the timing of energy resources into the resource plan using hydroelectric energy producing capability under critical water flow conditions.

DISPATCHABILITY: Is the operating control of a resource to follow changes in load in the most efficient and economic manner.

DSM: DEMAND-SIDE MANAGEMENT: DSM is a conservation resource which manages or reduces the amount of electricity power consumption required by our customers as a result of increases in the efficiency of energy use, production or distribution.

ECONOMETRICS: A combination of mathematics, statistics, and economic theory. Econometric forecasting is conceptually an extension of regression analysis. It allows for multiple dependence among variables included in the forecasting equations used in the model.

ECONOMY MARKET: (SPOT MARKET): Marketing energy produced and supplied from a more economical source in one system to substitute for energy being produced or capable of being produced by a less economical source in another system.

EEAF: ENVIRONMENTAL EXTERNALITY ADJUSTMENT FACTOR: A weighting and ranking method used by MPC to identify specific resource externality impacts relative to other resources.

EMA: ENERGY MANAGEMENT ASSOCIATES, INC.: Suppliers of the PROSCREEN and PROVIEW computer models, home office in Atlanta, Georgia.

END EFFECTS: The capital and production costs of a resource plan beyond the 1992 -2000 planning period.

ENERGY: The megawatt hours (mwh) supplied to or used by an individual customer, a group of customers, or a class of customers. Energy use in megawatt hours is determined by measurement or by calculation.

ENERGY LOSS: The general term applied to energy lost in the operation of an electric system. Losses occur principally as waste heat in electrical conductors and apparatus. Energy losses are measured in kilowatt-hours or megawatt-hours.

ENVIRONMENTAL EXTERNALITIES: Any costs or benefits of goods or services that are not accounted for in the price of the goods or services. Specifically, the term given to the effects of pollution and other environmental effects from power plants or conservation measures.

EXOGENOUS VARIABLE: An exogenous variable is one whose value is determined outside the model or system. Also known as an independent or explanatory variable, used in a casual relationship to predict values of a dependent variable.

FIRM CAPACITY: That portion of a customer's capacity requirements for which service is assured by the utility provider.

FIRM ENERGY: That portion of a customer's energy load for which service is assured by the utility provider. That portion for which service is not assured is referred to as "interruptible".

FIRMING HYDROELECTRIC SECONDARY ENERGY: Allows using the hydroelectric secondary energy as a firm energy resource. The firming is accomplished by running a firming resource such as a combustion turbine whenever the generation from the hydroelectric system is less than average and no other lower cost resource is available.

FLUIDIZED BED: Similar to a conventional coal-fired steam plant except for the manner in which the coal is burned. The coal is burned in a bed where limestone and air are fed into the combustion process. The calcium in the limestone reacts with the sulfur in the coal to form a removable solid waste. This results in a significant reduction in SO2 emissions. The heat generated is used to convert water into steam. The steam is then fed into a steam turbine that turns an electrical generator to produce electricity. This technology can use fuels other than coal, such as waste coal, coke, wood chips and municipal solid waste.

FORCED OUTAGE RESERVES: The reserve capacity a utility company must provide in order to insure reliable system operation in the event of unit failures.

FORECASTING: The prediction of future values of a variable based on known or past values of that variable or other related variables. Alternatively, forecasts may be based on expert judgements, which in turn are based on historical data and experience.

GEOTHERMAL RESOURCE: Geothermal resources can be located only in areas where heated rock lies at a shallow depth below the earth's surface. Wells are drilled to allow extraction of the thermal energy. If steam is available, it can be used to directly power a conventional turbine generator. If steam is not available, water is used to transfer the thermal energy to the surface. The thermal energy is then transferred to another fluid to power a conventional turbine generator.

HYDROELECTRIC SECONDARY ENERGY: The 50 average MW difference between hydroelectric energy production at average water conditions and critical water conditions is MPC's non-firm (or secondary) hydroelectric energy. In any given year, the secondary energy may not be available due to water conditions.

INTEGRATED GASIFICATION COMBINED CYCLE: An integrated gasification combined cycle unit uses a gasification plant to produce a fuel gas from coal, waste coal or some other fuel. The fuel gas is then used as the fuel for a combined cycle unit.

INTEGRATED LEAST COST RESOURCE PLAN: A plan which, given system reliability,

is the best balance of supply-side, demand-side, existing, and future resource options with the lowest societal total cost.

INTERRUPTIBLE LOAD: Load that by contract, can be interrupted in the event of a power supply deficiency.

KW: KILOWATT: 1,000 watts

KWH: KILOWATT-HOUR: A basic unit of electrical energy that equals one kilowatt of power applied for one hour.

LEVELIZED ANNUAL COST (Nominal): Where the cost occurs annually for a specific number of years and remains the same for that period.

MEDIAN WATER HYDROELECTRIC GENERATION: MPC's 75 year water data base is normally distributed, which means average water and median water are the same. See Average Water Hydroelectric Energy.

MODEL: A decision-making aid that draws actionable knowledge from sets of data.

MPSC: MONTANA PUBLIC SERVICE COMMISSION: The commission is made up of five elected positions and is a regulatory commission established by the state to oversee activities of utilities as defined by statute.

MULTI-ATTRIBUTE DECISION RULE: MPC's Multi-Attribute Decision Rule 'balances' the concerns of the customer, investors, quantifiable and nonquantifiable risk, and environmental impacts. It is used to evaluate resource plans against each other.

MW: MEGAWATT: The electrical unit of power that equals 1,000 kilowatts, or 1,000,000 watts.

MILL: A tenth of a cent. The cost of electricity is often given in mills per kilowatt-hour.

PEAK CAPACITY: The maximum capacity of a system to meet loads.

PEAK DEMAND: The greatest demand on an electric system during a prescribed demand interval, be it hourly, daily, monthly, or annually. MPC's annual peak occurs during the winter months.

PEAKING RESOURCE: A generating resource which is normally operated to provide power during maximum load periods.

PRESENT VALUE: The worth of future returns or costs in terms of their current value. To obtain a present value, an interest rate is used to discount these future returns and costs.

PROSCREEN: A computer program by Energy Management Associates, Inc. (EMA), that integrates the major disciplines within a utility and evaluates alternative plans under uncertainty.

The various modules of the system include the Load Forecast Adjustment (LFA), Generation and Fuel (GAF), Capital Expenditure and Recovery (CER), and Financial Reporting and Analysis (FIR).

PROVIEW: A least cost resource optimization program that uses dynamic programming to generate plans and determine revenue requirements, total cost, or rates. PROVIEW is a product of Energy Management Associates, Inc. (EMA), Atlanta, Georgia.

PULVERIZED COAL UNIT: A generating unit in which coal is crushed to powder and injected into a boiler firebox where it is combusted. The firebox heats water to create steam which is then fed into a steam turbine that turns an electrical generator to produce electricity. Pollution control equipment is generally located at the "back end" of the plant before pollutants go up the stack. This technology is used at the JE Corette Plant and Colstrip Units.

PUMPED HYDRO: Pumped hydro uses an upper and a lower storage reservoir and an underground power house. Neither of the reservoirs need to be a natural stream or lake. Water is pumped from the lower to upper reservoir during off-peak hours. During the generating cycle, water is discharged from the upper reservoir through the reversible turbine-generator to produce power. Depending upon the location, the environmental impacts of pumped hydro plants may be very low.

QF'S: QUALIFYING FACILITIES: A qualifying facility is a power production facility that qualifies for special treatment under a 1978 federal law - Public Utility Regulatory Policies Act (PURPA). PURPA requires a utility to buy the power produced by the qualifying facility at a price equal to that which the utility would other wise pay if it were to build its own power plant or buy the power from another source. A qualifying facility must generate its power using cogeneration, biomass, waste, geo-thermal energy, or renewable resources, such as solar and wind, and depending on the energy source and the time at which the facility is constructed, its size may be limited to 80 megawatts or smaller. PURPA prohibits utilities from owning a majority interest in qualifying facilities.

RESOURCE PLAN: A combination of individual resources that meet MPC customer's future electrical needs.

RFP: REQUEST FOR PROPOSAL: A competitive bidding process in which a utility requests proposals from suppliers (other utilities, small power producers, etc.) to fulfill the need to meet future load. MPC's all source RFP was opened for bids to supply power to MPC in the latter half of the 1990's. MPC anticipated completion of its RFP process by the end of 1992.

RISK: A quantifiable or subjective measure of the exposure to costs or other undesirable outcomes associated with an action taken in the face of uncertainty.

ROBUST PLAN: A plan that withstands and meets the criteria outlined in a multi-attribute decision rule (objective function) to minimize the affects of the unknown.

SOCIETAL COSTS: Societal Costs include both the direct and indirect <u>costs</u> and <u>benefits</u> associated with resource acquisitions.

STUDY PERIOD: The study period used in the optimization study was the planning period from 1992 through 2000 adjusted for infinite end effects of the resources timed into the Resource Plan (model base year of 1991 out to 2030).

SUPPLY-SIDE RESOURCES: Resources which physically generate (supplies) power to the power grid (ie: hydro, thermal, wind).

TEMPLATE: A spreadsheet that ties specific program information and load information together with assumptions of possible penetration rates, customer costs, estimated cost of promotion and incentives in order to calculate DSM energy and peak savings on a 20-year cycle.

TOTAL COSTS: The sum of the utility revenue requirement and customer costs necessary to acquire demand-side resource.

TREND: Previous values of a variable are weighted and combined to produce estimates of future values.

WATT: The electrical unit of power or rate of doing work. The rate of energy transfer equivalent to one ampere flowing under a pressure of one volt at unity power factor. It is analogous to horsepower or foot-pounds per minute of mechanical power. One horsepower is equivalent to approximately 746 watts.

WEIGHTED COST OF CAPITOL: The return asked, or being asked, by investors for the use of their money committed to investment in utility companies, expressed as percentage of the capital funds (debt, preferred stock, common equity).

WIND RESOURCE: A wind turbine captures the energy in wind and uses it to drive an electrical generator. Wind turbines can only produce electricity when the wind is blowing. They are most effective in areas with high average annual wind velocities. Many areas in Montana appear suited for small- and large-scale wind resource development.

APPENDIX A

ILLUSTRATIONS

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ILLUSTRATION 1

INTEGRATED LEAST COST PLANNING OPTIMIZATION PROCESS OVERVIEW OF THE GENERALIZED FLOW OF INFORMATION

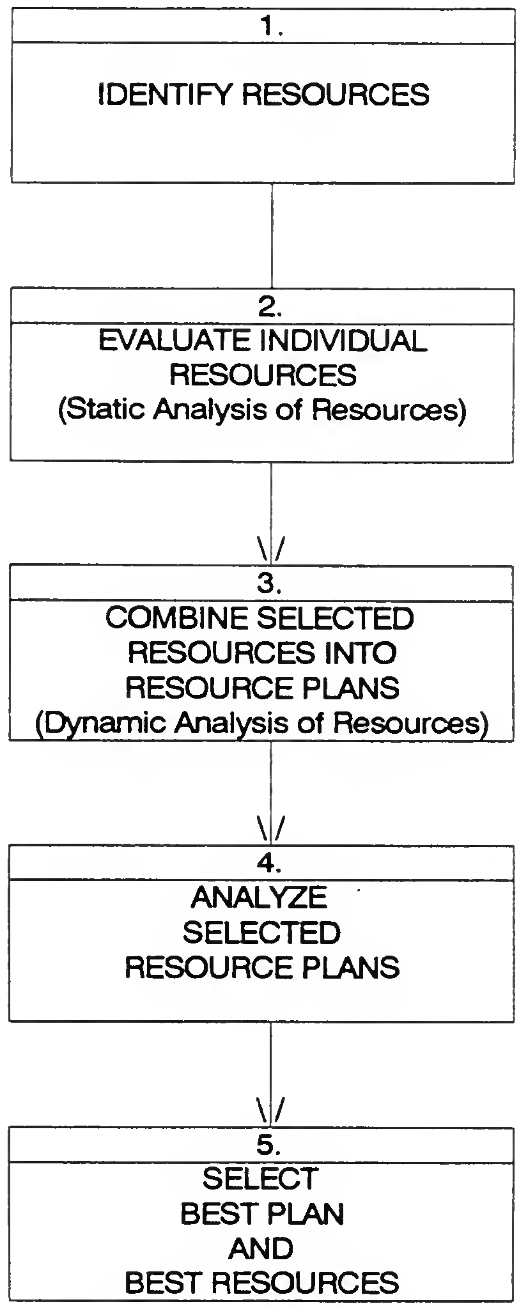

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ILLUSTRATION 2
INTEGRATED LEAST COST PLANNING OPTIMIZATION PROCESS

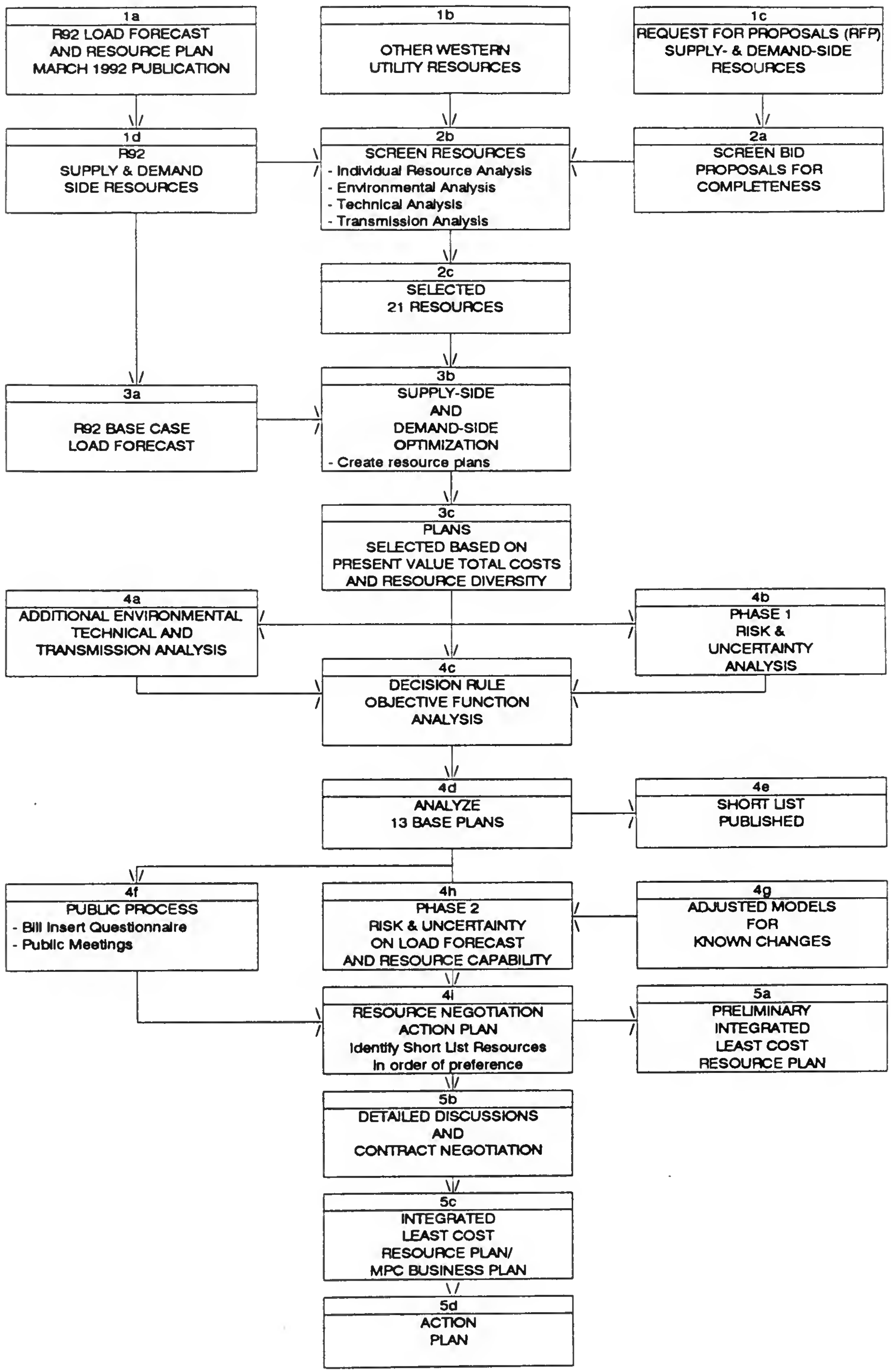
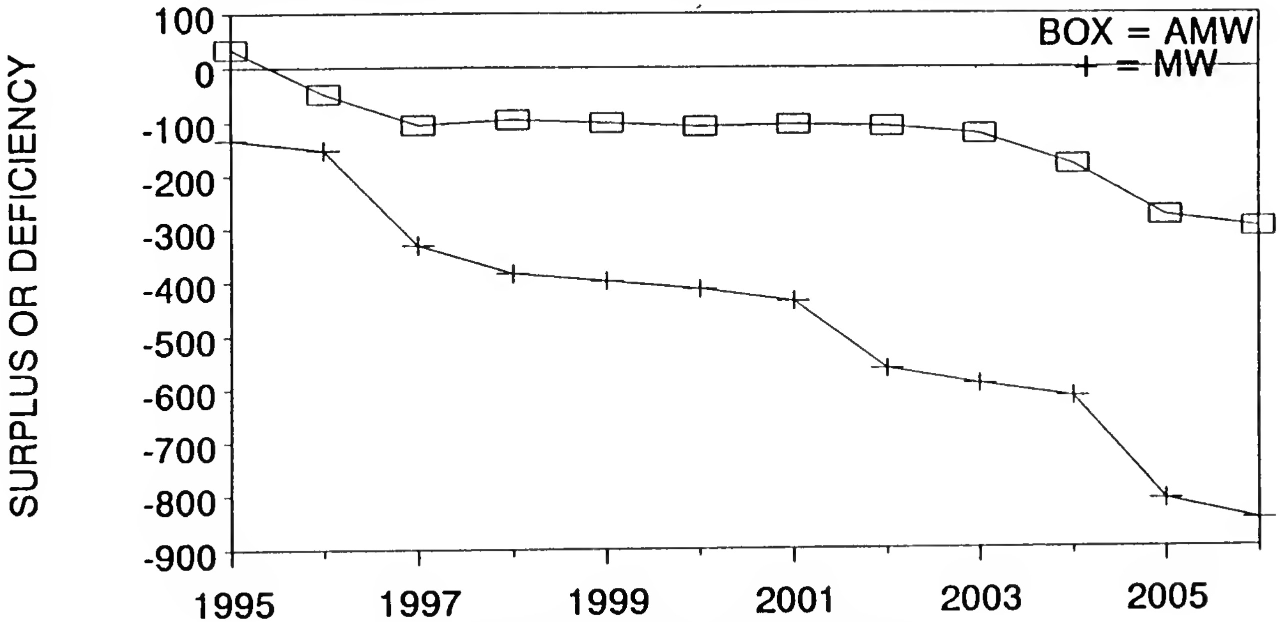


ILLUSTRATION 3

1995-06 NEED BEFORE DEMAND-SIDE RESOURCE



NO DEMAND-SIDE RESOURCE

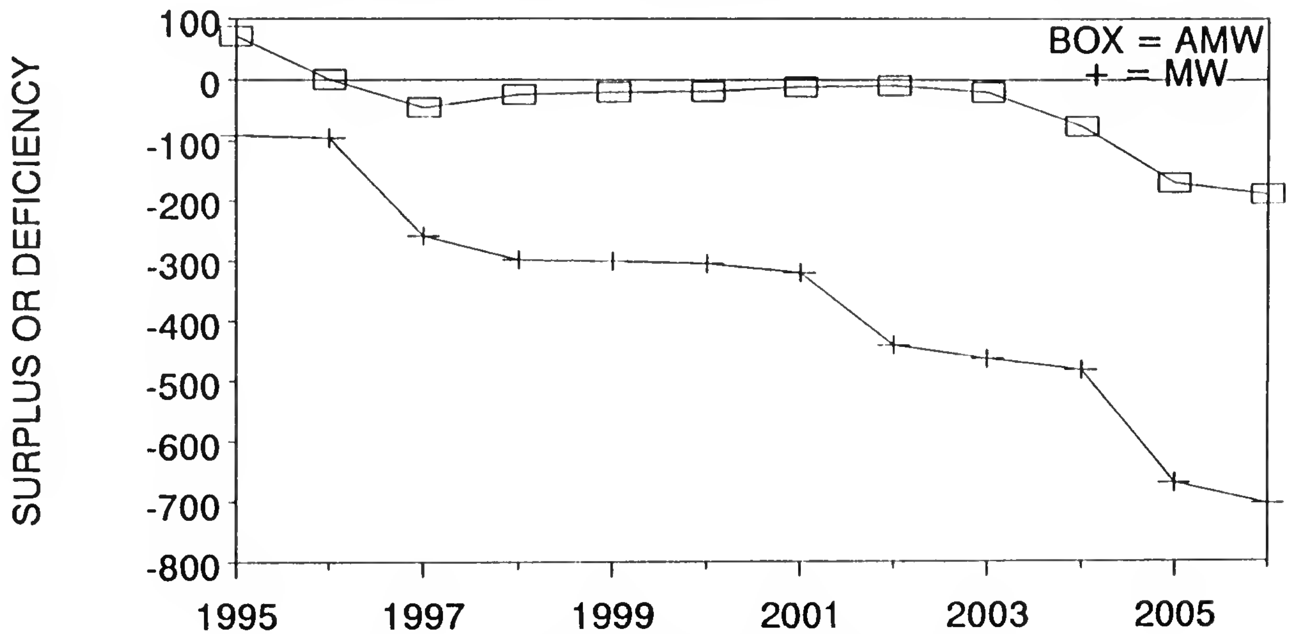
SURPLUS(DEFICIENCY)		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
AVG MW:	ADDED:	0	1	6	19	19	22	22	22	23	23	23	23
	+/-:	35	-47	-105	-96	-101	-108	-105	-108	-122	-180	-278	-300
		HYDRO @ CRITICAL WATER											
JAN MW:	ADDED:	0	0	2	17	17	20	20	20	21	21	21	21
	+/-:	-133	-152	-330	-383	-397	-413	-436	-563	-592	-617	-811	-849

MDL70>C:R92\TAB_V4.WK1

04/04/92

ILLUSTRATION 4

1995-06 NEED WITH DEMAND-SIDE RESOURCE



SASA DEMAND-SIDE RESOURCE ONLY

SURPLUS(DEFICIENCY)

		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
AVG MW:	ADDED:	37	49	66	91	100	111	115	120	125	127	131	134
	+/-:	72	1	-45	-24	-20	-19	-12	-10	-20	-76	-170	-189
		HYDRO @ CRITICAL WATER											
JAN MW:	ADDED:	42	57	74	102	114	129	136	143	150	156	162	166
	+/-:	-91	-95	-258	-298	-300	-304	-320	-440	-463	-482	-670	-704

MDL70>C:R92\TAB_V4.WK1

04/04/92

ILLUSTRATION 5

1992 LOAD FORECAST
ENERGY LOAD, PEAK LOAD AND SALES BY LARGE CLASS
1991-2015 BASE CASE FORECAST

	SALES IN MWH														LOAD IN aMW OR MW				
	RESIDENTIAL		COMMERCIAL		INDUSTRIAL		CONTRACT		OTHER		RAILROADS		TOTAL SALES		ENERGY		PEAK *		LOAD FACTOR
YEAR	mwh	%gth	mwh	%gth	mwh	%gth	mwh	%gth	mwh	%gth	mwh	%gth	mwh	%gth	aMW	%gth	MW	%gth	
1991	1778583	0.0%	1947063	0.7%	728538	-3.6%	2146320	3.7%	702770	-0.4%			7303274	0.8%	934	-0.4%	1424	-5.3%	0.6559
1992	1791761	0.7%	1976851	1.5%	746314	2.4%	2240014	4.4%	712892	1.4%			7467832	2.3%	955	2.2%	1456	2.2%	0.6559
1993	1813616	1.2%	2015827	2.0%	769668	3.1%	2283328	1.9%	724139	1.6%			7606578	1.9%	974	2.0%	1486	2.1%	0.6555
1994	1837328	1.3%	2050254	1.7%	805920	4.7%	2387173	4.5%	730624	0.9%			7811300	2.7%	1000	2.7%	1521	2.4%	0.6575
1995	1862475	1.4%	2091740	2.0%	832200	3.3%	2431181	1.8%	737740	1.0%			7955337	1.8%	1019	1.9%	1550	1.9%	0.6574
1996	1886065	1.3%	2149950	2.8%	858480	3.2%	2449281	0.7%	745704	1.1%			8089481	1.7%	1035	1.6%	1575	1.6%	0.6571
1997	1909282	1.2%	2206552	2.6%	884754	3.1%	2453393	0.2%	753164	1.0%			8207145	1.5%	1051	1.5%	1598	1.5%	0.6577
1998	1929732	1.1%	2237617	1.4%	909778	2.8%	2451193	-0.1%	758937	0.8%			8287257	1.0%	1061	1.0%	1615	1.1%	0.6570
1999	1950193	1.1%	2229840	-0.3%	931126	2.3%	2447993	-0.1%	762567	0.5%			8321719	0.4%	1066	0.5%	1625	0.6%	0.6560
2000	1972419	1.1%	2263038	1.5%	953548	2.4%	2445193	-0.1%	768937	0.8%			8403135	1.0%	1077	1.0%	1644	1.2%	0.6551
2001	1993672	1.1%	2318808	2.5%	976134	2.4%	2442493	-0.1%	776038	0.9%			8507145	1.2%	1089	1.1%	1663	1.2%	0.6548
2002	2016616	1.2%	2382487	2.7%	996960	2.1%	2442983	0.0%	784039	1.0%			8623085	1.4%	1105	1.5%	1687	1.4%	0.6550
2003	2040041	1.2%	2447657	2.7%	1018311	1.9%	2443363	0.0%	792206	1.0%			8739579	1.4%	1120	1.4%	1712	1.5%	0.6542
2004	2066146	1.3%	2497273	2.0%	1037836	2.1%	2444743	0.1%	800140	1.0%			8846138	1.2%	1134	1.3%	1735	1.3%	0.6536
2005	2094513	1.4%	2588659	3.7%	1062381	2.4%	2445123	0.0%	810401	1.3%			9001078	1.8%	1154	1.8%	1765	1.7%	0.6538
2006	2131129	1.7%	2688850	3.9%	1086219	2.2%	2446003	0.0%	822699	1.5%			9174901	1.9%	1177	2.0%	1799	1.9%	0.6543
2007	2168895	1.8%	2782713	3.5%	1109300	2.1%	2449283	0.1%	834842	1.5%			9345033	1.9%	1198	1.8%	1832	1.8%	0.6539
2008	2205705	1.7%	2873338	3.3%	1129324	1.8%	2452563	0.1%	846829	1.4%			9507759	1.7%	1220	1.8%	1863	1.7%	0.6549
2009	2244851	1.8%	2920075	1.6%	1151339	1.9%	2455343	0.1%	856424	1.1%			9628032	1.3%	1236	1.3%	1890	1.4%	0.6540
2010	2286632	1.9%	3046312	4.3%	1174441	2.0%	2457623	0.1%	871031	1.7%			9836040	2.2%	1261	2.0%	1927	2.0%	0.6544
2011	2337430	2.2%	3188563	4.7%	1199396	2.1%	2460403	0.1%	888021	2.0%			10073813	2.4%	1293	2.5%	1971	2.3%	0.6560
2012	2386625	2.1%	3294444	3.3%	1221826	1.9%	2462683	0.1%	902918	1.7%			10268498	1.9%	1318	1.9%	2008	1.9%	0.6564
2013	2436648	2.1%	3347985	1.6%	1243385	1.8%	2465963	0.1%	914707	1.3%			10408689	1.4%	1336	1.4%	2039	1.5%	0.6552
2014	2485515	2.0%	3472061	3.7%	1263617	1.6%	2469243	0.1%	930384	1.7%			10620820	2.0%	1364	2.1%	2078	1.9%	0.6564
2015	2537288	2.1%	3540593	2.0%	1286359	1.8%	2472523	0.1%	943477	1.4%			10780240	1.5%	1384	1.5%	2110	1.5%	0.6559
1960-90	4.1%		5.5%		3.6%		1.8%		3.0%				3.3%		3.2%		3.4%		
CAGR ** 1991-2015	1.5%		2.5%		2.4%		0.6%		1.2%				1.6%		1.6%		1.6%		

* Assumes normal weather conditions

ILLUSTRATION 6

ENERGY LOAD, PEAK LOAD AND SALES BY LARGE CLASS
1960-1991 ACTUAL, 1992-2016 BUSINESS PLAN FORECAST

HISTORICAL

	SALES IN MWH														LOAD IN aMW OR MW				
	RESIDENTIAL		COMMERCIAL		INDUSTRIAL		CONTRACT		OTHER		RAILROADS		TOTAL SALES		ENERGY		PEAK		LOAD FACTOR
YEAR	mwh	%gth	mwh	%gth	mwh	%gth	mwh	%gth	mwh	%gth	mwh	%gth	mwh	%gth	aMW	%gth	MW	%gth	
1960	520148		368535		256292		1203821		283091		85276		2717163		359		545		0.6594
1961	547422	5.2%	403542	9.5%	268753	4.9%	1169759	-2.8%	316943	12.0%	78899	-7.5%	2785318	2.5%	376	4.7%	585	7.3%	0.6431
1962	582157	6.3%	427741	6.0%	281419	4.7%	1265505	8.2%	356644	12.5%	86794	10.0%	3000300	7.7%	392	4.3%	576	-1.5%	0.6806
1963	597651	2.7%	451264	5.5%	292003	3.8%	1201127	-5.1%	410570	15.1%	83554	-3.7%	3036170	1.2%	399	1.8%	635	10.2%	0.6294
1964	632082	5.8%	481896	6.8%	310470	6.3%	1429250	19.0%	419860	2.3%	70785	-15.3%	3344344	10.2%	438	9.8%	650	2.4%	0.6742
1965	673483	6.5%	520797	8.1%	316174	1.8%	1556258	8.9%	450240	7.2%	81033	14.5%	3597985	7.6%	469	7.1%	683	5.1%	0.6874
1966	695996	3.3%	553713	6.3%	373871	18.2%	1771400	13.8%	478889	6.4%	87476	8.0%	3961344	10.1%	510	8.7%	737	7.9%	0.6924
1967	717091	3.0%	589852	6.5%	374839	0.3%	1317252	-25.6%	448000	-6.5%	81684	-6.6%	3528717	-10.9%	466	-8.6%	703	-4.6%	0.6633
1968	764937	6.7%	643022	9.0%	387509	3.4%	1465285	11.2%	431798	-3.6%	89039	9.0%	3761588	6.6%	495	6.2%	757	7.7%	0.6551
1969	820698	7.3%	690395	7.4%	402059	3.8%	1856521	26.7%	432297	0.1%	56734	-36.3%	4258704	13.2%	542	9.5%	748	-1.2%	0.7251
1970	850321	3.6%	740096	7.2%	418275	4.0%	1899701	2.3%	423403	-2.1%	72342	27.5%	4404137	3.4%	564	4.1%	782	4.5%	0.7219
1971	912861	7.4%	796792	7.7%	494221	18.2%	1639328	-13.7%	446985	5.6%	79943	10.5%	4370130	-0.8%	561	-0.5%	834	6.6%	0.6727
1972	984848	7.9%	856757	7.5%	565532	14.4%	1666499	1.7%	465900	4.2%	80593	0.8%	4620130	5.7%	589	5.0%	867	4.0%	0.6795
1973	1016702	3.2%	916428	7.0%	604061	6.8%	1414329	-15.1%	499786	7.3%	51569	-36.0%	4502875	-2.5%	578	-1.9%	843	-2.8%	0.6856
1974	1043593	2.6%	930212	1.5%	606698	0.4%	1525603	7.9%	505315	1.1%	22577	-56.2%	4633999	2.9%	599	3.6%	823	-2.4%	0.7286
1975	1143941	9.6%	996749	7.2%	587023	-3.2%	1406861	-7.8%	532902	5.5%			4667477	0.7%	606	1.2%	880	6.9%	0.6889
1976	1205322	5.4%	1060597	6.4%	674948	15.0%	1523939	8.3%	556341	4.4%			5021152	7.6%	650	7.3%	930	5.7%	0.6998
1977	1299608	7.8%	1129770	6.5%	668734	-0.9%	1555070	2.0%	575076	3.4%			5228258	4.1%	687	5.7%	1026	10.3%	0.6698
1978	1454858	11.9%	1227173	8.6%	673483	0.7%	1538519	-1.1%	631492	9.8%			5525525	5.7%	719	4.7%	1095	6.7%	0.6572
1979	1560303	7.2%	1323282	7.8%	706090	4.8%	1635349	6.3%	672082	6.4%			5897105	6.7%	772	7.4%	1154	5.4%	0.6690
1980	1538693	-1.4%	1363747	3.1%	662738	-6.1%	1381666	-15.5%	634226	-5.6%			5581070	-5.4%	745	-3.5%	1171	1.5%	0.6363
1981	1547579	0.6%	1418839	4.0%	635931	-4.0%	1453401	5.2%	625399	-1.4%			5681149	1.8%	746	0.1%	1124	-4.0%	0.6645
1982	1706174	10.2%	1507494	6.2%	624485	-1.8%	1439265	-1.0%	632554	1.1%			5909972	4.0%	766	2.7%	1135	1.0%	0.6756
1983	1674886	-1.8%	1628567	8.0%	647388	3.7%	1468830	2.1%	649351	2.7%			6063344	2.6%	786	2.6%	1283	13.0%	0.6130
1984	1824344	8.9%	1682008	3.3%	656510	1.4%	1455762	-0.9%	707934	9.0%			6326559	4.3%	816	3.8%	1221	-4.8%	0.6688
1985	1888050	3.5%	1741703	3.5%	704011	7.2%	1353468	-7.0%	728036	2.8%			6415268	1.4%	839	2.8%	1295	6.1%	0.6480
1986	1766168	-6.5%	1709024	-1.9%	725869	3.1%	1559760	15.2%	696123	-4.4%			6456944	0.6%	838	-0.1%	1233	-4.8%	0.6804
1987	1733514	-1.8%	1783160	4.3%	643104	-11.4%	1895900	21.6%	664628	-4.5%			6720306	4.1%	863	3.0%	1237	0.3%	0.6981
1988	1800410	3.9%	1877405	5.3%	664783	3.4%	1981327	4.5%	707667	6.5%			7031591	4.6%	902	4.5%	1287	4.0%	0.7009
1989	1836345	2.0%	1913526	1.9%	713970	7.4%	2035180	2.7%	712143	0.6%			7211165	2.6%	929	3.0%	1420	10.3%	0.6542
1990	1778360	-3.2%	1932846	1.0%	755797	5.9%	2069380	1.7%	705761	-0.9%			7242145	0.4%	938	1.0%	1504	5.9%	0.6237
1991	1819780	2.3%	2003492	3.7%	732921	-3.0%	2155252	4.1%	715863	1.4%			7427308	2.6%	950	1.3%	1362	-9.4%	0.6975

ILLUSTRATION 6
Page 2 of 4

ENERGY LOAD, PEAK LOAD AND SALES BY LARGE CLASS
1992-2016 BASE CASE FORECAST

	SALES IN MWH														LOAD IN aMW OR MW				
	RESIDENTIAL		COMMERCIAL		INDUSTRIAL		CONTRACT		OTHER		RAILROADS		TOTAL SALES		ENERGY		PEAK *		LOAD FACTOR
YEAR	mwh	%gth	mwh	%gth	mwh	%gth	mwh	%gth	mwh	%gth	mwh	%gth	mwh	%gth	aMW	%gth	MW	%gth	
1992	1786444	-1.8%	2034498	1.5%	748640	2.1%	2275289	5.6%	706013	-1.4%			7550884	1.7%	966	1.7%	1412	3.7%	0.6841
1993	1809317	1.3%	2082021	2.3%	772500	3.2%	2293340	0.8%	712691	0.9%			7669870	1.6%	982	1.7%	1439	1.9%	0.6824
1994	1838103	1.6%	2135701	2.6%	805289	4.2%	2366540	3.2%	721171	1.2%			7866804	2.6%	1007	2.5%	1475	2.5%	0.6827
1995	1878058	2.2%	2199114	3.0%	831254	3.2%	2422396	2.4%	731842	1.5%			8062664	2.5%	1033	2.6%	1511	2.4%	0.6837
1996	1925538	2.5%	2271564	3.3%	863934	3.9%	2450138	1.1%	744430	1.7%			8255603	2.4%	1058	2.4%	1546	2.3%	0.6843
1997	1964614	2.0%	2348129	3.4%	884667	2.4%	2460236	0.4%	755507	1.5%			8413154	1.9%	1078	1.9%	1573	1.7%	0.6853
1998	1996270	1.6%	2413437	2.8%	908831	2.7%	2466136	0.2%	764915	1.2%			8549589	1.6%	1096	1.7%	1599	1.7%	0.6854
1999	2029665	1.7%	2457947	1.8%	933626	2.7%	2470538	0.2%	773463	1.1%			8665238	1.4%	1111	1.4%	1621	1.4%	0.6854
2000	2062174	1.6%	2491388	1.4%	955064	2.3%	2474036	0.1%	781434	1.0%			8764096	1.1%	1123	1.1%	1640	1.2%	0.6848
2001	2091009	1.4%	2513934	0.9%	977527	2.4%	2480086	0.2%	787838	0.8%			8850395	1.0%	1134	1.0%	1656	1.0%	0.6848
2002	2119424	1.4%	2533780	0.8%	999735	2.3%	2479598	-0.0%	794205	0.8%			8926741	0.9%	1144	0.9%	1671	0.9%	0.6846
2003	2147441	1.3%	2554029	0.8%	1022914	2.3%	2479996	0.0%	800531	0.8%			9004911	0.9%	1154	0.9%	1685	0.8%	0.6849
2004	2175071	1.3%	2576564	0.9%	1045870	2.2%	2480396	0.0%	807100	0.8%			9085001	0.9%	1164	0.9%	1700	0.9%	0.6847
2005	2202269	1.3%	2602438	1.0%	1066813	2.0%	2481796	0.1%	813426	0.8%			9166741	0.9%	1175	0.9%	1716	0.9%	0.6847
2006	2238137	1.6%	2642870	1.6%	1088353	2.0%	2482196	0.0%	822175	1.1%			9273732	1.2%	1189	1.2%	1740	1.4%	0.6833
2007	2273582	1.6%	2686266	1.6%	1110611	2.0%	2484596	0.1%	831020	1.1%			9386075	1.2%	1203	1.2%	1763	1.3%	0.6824
2008	2308567	1.5%	2731835	1.7%	1132228	1.9%	2487996	0.1%	840090	1.1%			9500717	1.2%	1219	1.3%	1788	1.4%	0.6818
2009	2343142	1.5%	2778673	1.7%	1153313	1.9%	2490398	0.1%	848807	1.0%			9614331	1.2%	1234	1.2%	1812	1.3%	0.681
2010	2377332	1.5%	2826050	1.7%	1175224	1.9%	2493796	0.1%	857671	1.0%			9730073	1.2%	1249	1.2%	1837	1.4%	0.6799
2011	2420722	1.8%	2884010	2.1%	1196169	1.8%	2496198	0.1%	868647	1.3%			9865744	1.4%	1266	1.4%	1868	1.7%	0.6777
2012	2464587	1.8%	2942751	2.0%	1217301	1.8%	2499598	0.1%	879926	1.3%			10004161	1.4%	1284	1.4%	1901	1.8%	0.6754
2013	2508461	1.8%	3007321	2.0%	1238534	1.7%	2502996	0.1%	890897	1.2%			10143210	1.4%	1301	1.3%	1932	1.6%	0.6734
2014	2553268	1.8%	3064080	2.1%	1258960	1.6%	2506398	0.1%	902325	1.3%			10285030	1.4%	1321	1.5%	1967	1.8%	0.6716
2015	2597631	1.7%	3126219	2.0%	1279635	1.6%	2510796	0.2%	913702	1.3%			10427984	1.4%	1339	1.4%	2000	1.7%	0.6695
2016	2643517	1.8%	3190734	2.1%	1298559	1.5%	2514196	0.1%	925655	1.3%			10572662	1.4%	1357	1.3%	2033	1.7%	0.6675
1960-91	4.0%		5.5%		3.4%		1.9%		3.0%				3.2%		3.1%		3.0%		
CAGR ** 1992-2016	1.6%		1.9%		2.3%		0.4%		1.1%				1.4%		1.4%		1.5%		

* Assumes normal weather conditions
** Compound Annual Growth Rate
R93 Outputs, Page 2 of 4

ILLUSTRATION 6
Page 3 of 4

ENERGY LOAD, PEAK LOAD AND SALES BY LARGE CLASS
1992-2016 HIGH CASE FORECAST

	SALES IN MWH														LOAD IN aMW OR MW				
	RESIDENTIAL		COMMERCIAL		INDUSTRIAL		CONTRACT		OTHER		RAILROADS		TOTAL SALES		ENERGY		PEAK *		LOAD FACTOR
YEAR	mwh	%gth	mwh	%gth	mwh	%gth	mwh	%gth	mwh	%gth	mwh	%gth	mwh	%gth	aMW	%gth	MW	%gth	
1992	1786444		2034498		748840		2276289		706013				7550884		966		1412		0 6841
1993	1609317	1.3%	2082021	2.3%	772500	3.2%	2319376	1.9%	714893	1.3%			7698108	1.9%	985	2.0%	1443	2.2%	0 6826
1994	1849944	2.2%	2145608	3.1%	635037	6.1%	2529436	9.1%	727255	1.7%			8087280	5.1%	1036	5.2%	1511	4.7%	0.6856
1995	1904939	3.0%	2227688	3.8%	861124	3.1%	2585786	2.2%	742858	2.1%			8322393	2.9%	1066	2 9%	1552	2.7%	0.6869
1996	1970296	3.4%	2325970	4.4%	889109	3.2%	2624198	1.5%	761278	2.5%			8570847	3.0%	1099	3.1%	1594	2 7%	0.6895
1997	2027326	2.9%	2433550	4.6%	912408	2.6%	2645670	0.8%	778518	2.3%			8797473	2 6%	1128	2.6%	1633	2.4%	0.6906
1998	2076819	2.4%	2532432	4.1%	937036	2.7%	2664940	0.7%	794249	2.0%			9005477	2.4%	1155	2.4%	1669	2.2%	0.692
1999	2128184	2.5%	2610288	3.1%	970059	3.5%	2683600	0.7%	809168	1.9%			9201300	2.2%	1180	2.2%	1703	2.0%	0.6929
2000	2178679	2.4%	2675465	2.5%	1000511	3.1%	2702700	0.7%	822439	1.6%			9379794	1 9%	1202	1.9%	1734	1.8%	0.6932
2001	2235233	2.6%	2739187	2.4%	1031403	3.1%	2721280	0.7%	836288	1.7%			9563390	2.0%	1227	2.1%	1766	1.8%	0.6948
2002	2291551	2.5%	2797761	2.1%	1062745	3.0%	2740340	0.7%	850000	1.6%			9742398	1.9%	1250	1.9%	1796	1.7%	0.696
2003	2347614	2.4%	2854490	2.0%	1091317	2.7%	2759710	0.7%	863579	1.6%			9916711	1.8%	1273	1 8%	1826	1.7%	0.6972
2004	2403404	2.4%	2911726	2.0%	1118639	2.5%	2779420	0.7%	877331	1.6%			10090520	1.8%	1294	1.6%	1854	1.5%	0.698
2005	2458848	2.3%	2971089	2.0%	1145377	2.4%	2796790	0.7%	890795	1.5%			10264900	1.7%	1318	1.9%	1884	1.6%	0.6996
2006	2519376	2.5%	3040212	2.3%	1171860	2.3%	2819570	0.7%	905832	1.7%			10456850	1.9%	1342	1.8%	1921	2.0%	0.6986
2007	2579473	2.4%	3111976	2.4%	1200516	2.4%	2839280	0.7%	920953	1.7%			10652180	1 9%	1368	1.9%	1958	1.9%	0.6987
2008	2839079	2.3%	3185913	2.4%	1229098	2.4%	2859130	0.7%	936302	1.7%			10849523	1.9%	1393	1.8%	1996	1.9%	0.6979
2009	2698233	2.2%	3261296	2.4%	1257861	2.3%	2879110	0.7%	951311	1.6%			11047812	1.8%	1418	1.8%	2032	1.8%	0.6978
2010	2756962	2.2%	3337496	2.3%	1286705	2.3%	2900480	0.7%	966485	1.6%			11248128	1.8%	1444	1.8%	2071	1.9%	0.6972
2011	2827016	2.5%	3426992	2.7%	1315201	2.2%	2920850	0.7%	984280	1.8%			11474339	2.0%	1474	2.1%	2118	2.3%	0.6959
2012	2897864	2.5%	3518199	2.7%	1343519	2.2%	2941170	0.7%	1002493	1.9%			11703245	2.0%	1504	2.0%	2164	2.2%	0.695
2013	2969294	2.5%	3611878	2.7%	1371944	2.1%	2962595	0 7%	1020592	1.8%			11936304	2.0%	1534	2.0%	2211	2.2%	0.6938
2014	3041219	2.4%	3708184	2.7%	1399698	2.0%	2983418	0.7%	1039108	1.8%			12171605	2.0%	1564	2.0%	2260	2.2%	0.692
2015	3113871	2.4%	3807286	2.7%	1427232	2.0%	3004140	0.7%	1057912	1.8%			12410442	2.0%	1595	2.0%	2309	2.2%	0.6908
2016	3167658	2.4%	3908842	2.7%	1454239	1.9%	3026485	0.7%	1077240	1.8%			12654465	2.0%	1627	2.0%	2358	2.1%	0.69
CAGR ** 1992-2016	2.4%		2.7%		2.6%		1.2%		1.8%				2.2%		2.2%		2.1%		

* Assumes normal weather conditions
** Compound Annual Growth Rate
R93 Outputs, Page 3 of 4

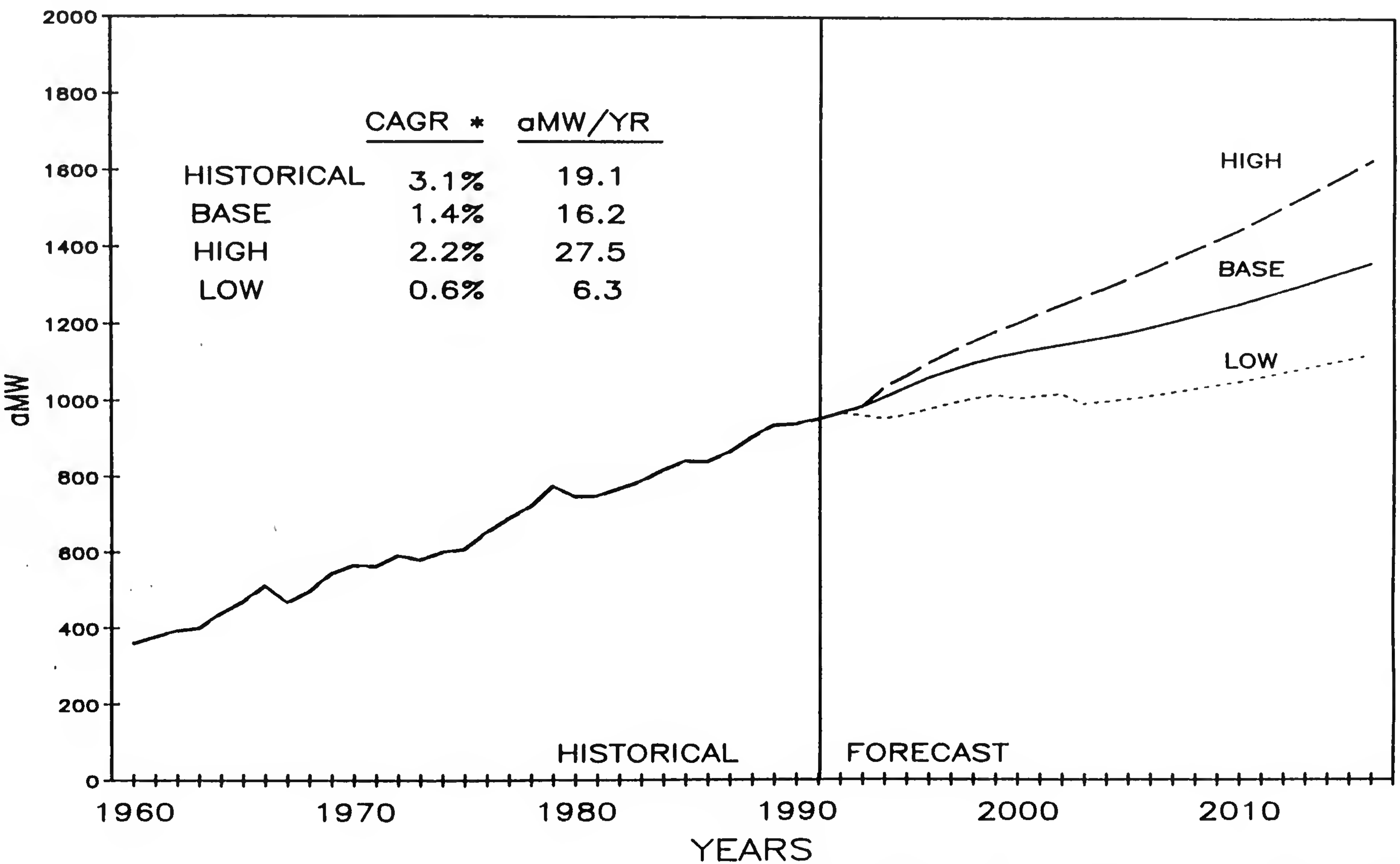
ILLUSTRATION 6
Page 4 of 4

ENERGY LOAD, PEAK LOAD AND SALES BY LARGE CLASS
1992-2016 LOW CASE FORECAST

	SALES IN MWH														LOAD IN aMW OR MW				
	RESIDENTIAL		COMMERCIAL		INDUSTRIAL		CONTRACT		OTHER		RAILROADS		TOTAL SALES		ENERGY		PEAK *		LOAD FACTOR
YEAR	mwh	%gth	mwh	%gth	mwh	%gth	mwh	%gth	mwh	%gth	mwh	%gth	mwh	%gth	aMW	%gth	MW	%gth	
1992	1786444		2034498		748640		2275289		706013				7550884		966		1412		0.6841
1993	1809317	1.3%	2082021	2.3%	772500	3.2%	2110627	-7.2%	712426	0.9%			7486892	-0.8%	958	-0.8%	1410	-0.1%	0.6794
1994	1828730	1.1%	2132337	2.4%	796075	3.1%	1955169	-7.4%	718901	0.9%			7431213	-0.7%	950	-0.8%	1408	-0.1%	0.6747
1995	1861471	1.8%	2189530	2.7%	828132	4.0%	1900229	-2.8%	727765	1.2%			7507127	1.0%	960	1.1%	1425	1.2%	0.6737
1998	1900191	2.1%	2249616	2.7%	845955	2.2%	1900229	0.0%	737949	1.4%			7633942	1.7%	976	1.7%	1447	1.5%	0.6745
1997	1930285	1.6%	2311966	2.8%	856189	1.2%	1900229	0.0%	746479	1.2%			7745149	1.5%	991	1.5%	1470	1.6%	0.6741
1998	1952857	1.2%	2362069	2.2%	868659	1.5%	1900229	0.0%	753267	0.9%			7837081	1.2%	1003	1.2%	1488	1.2%	0.6741
1999	1976948	1.2%	2391382	1.2%	888998	2.3%	1900229	0.0%	759158	0.8%			7916716	1.0%	1013	1.0%	1503	1.0%	0.674
2000	2000003	1.2%	2410068	0.8%	908765	2.2%	1743102	-8.3%	764469	0.7%			7826408	-1.1%	1002	-1.1%	1493	-0.7%	0.6711
2001	2019172	1.0%	2418588	0.4%	928130	2.1%	1743102	0.0%	768217	0.5%			7877210	0.6%	1009	0.7%	1504	0.7%	0.6709
2002	2037735	0.9%	2425022	0.3%	946643	2.0%	1743102	0.0%	771930	0.5%			7924432	0.6%	1015	0.6%	1513	0.6%	0.6709
2003	2055741	0.9%	2432282	0.3%	962403	1.7%	1497822	-14.1%	775595	0.5%			7723844	-2.5%	989	-2.6%	1484	-1.9%	0.6664
2004	2073228	0.9%	2442082	0.4%	977243	1.5%	1497822	0.0%	779494	0.5%			7769870	0.6%	995	0.6%	1493	0.6%	0.6664
2005	2090181	0.8%	2455289	0.5%	989446	1.2%	1497822	0.0%	783136	0.5%			7815874	0.6%	1001	0.6%	1504	0.7%	0.6656
2006	2114354	1.2%	2481368	1.1%	1001175	1.2%	1497822	0.0%	788863	0.7%			7883583	0.9%	1010	0.9%	1520	1.1%	0.6645
2007	2137979	1.1%	2510210	1.2%	1014035	1.3%	1497822	0.0%	794655	0.7%			7954701	0.9%	1019	0.9%	1537	1.1%	0.663
2008	2161049	1.1%	2540977	1.2%	1027297	1.3%	1497822	0.0%	800636	0.8%			8027784	0.9%	1028	0.9%	1554	1.1%	0.6615
2009	2183625	1.0%	2572767	1.3%	1039965	1.2%	1497822	0.0%	806240	0.7%			8100419	0.9%	1038	1.0%	1572	1.2%	0.6603
2010	2205753	1.0%	2604883	1.2%	1053264	1.3%	1497822	0.0%	811964	0.7%			8173686	0.9%	1047	0.9%	1590	1.1%	0.6585
2011	2235234	1.3%	2646385	1.6%	1067422	1.3%	1497822	0.0%	819371	0.9%			8265235	1.1%	1058	1.1%	1613	1.4%	0.6559
2012	2265011	1.3%	2686326	1.5%	1081196	1.3%	1497822	0.0%	827031	0.9%			8357386	1.1%	1071	1.2%	1638	1.5%	0.6538
2013	2295277	1.3%	2728517	1.6%	1094350	1.2%	1497822	0.0%	834482	0.9%			8450449	1.1%	1082	1.0%	1661	1.4%	0.6514
2014	2325353	1.3%	2771192	1.6%	1107539	1.2%	1497822	0.0%	842109	0.9%			8544016	1.1%	1095	1.2%	1686	1.5%	0.6495
2015	2355545	1.3%	2814743	1.6%	1120938	1.2%	1497822	0.0%	849804	0.9%			8638852	1.1%	1107	1.1%	1710	1.4%	0.6474
2016	2386285	1.3%	2859525	1.6%	1133777	1.1%	1497822	0.0%	857846	0.9%			8735255	1.1%	1119	1.1%	1736	1.5%	0.6446
CAGR **																			
1992-2016	1.2%		1.4%		1.7%		-1.7%		0.8%				0.6%		0.6%		0.9%		

* Assumes normal weather conditions
** Compound Annual Growth Rate
R93 Outputs, Page 4 of 4

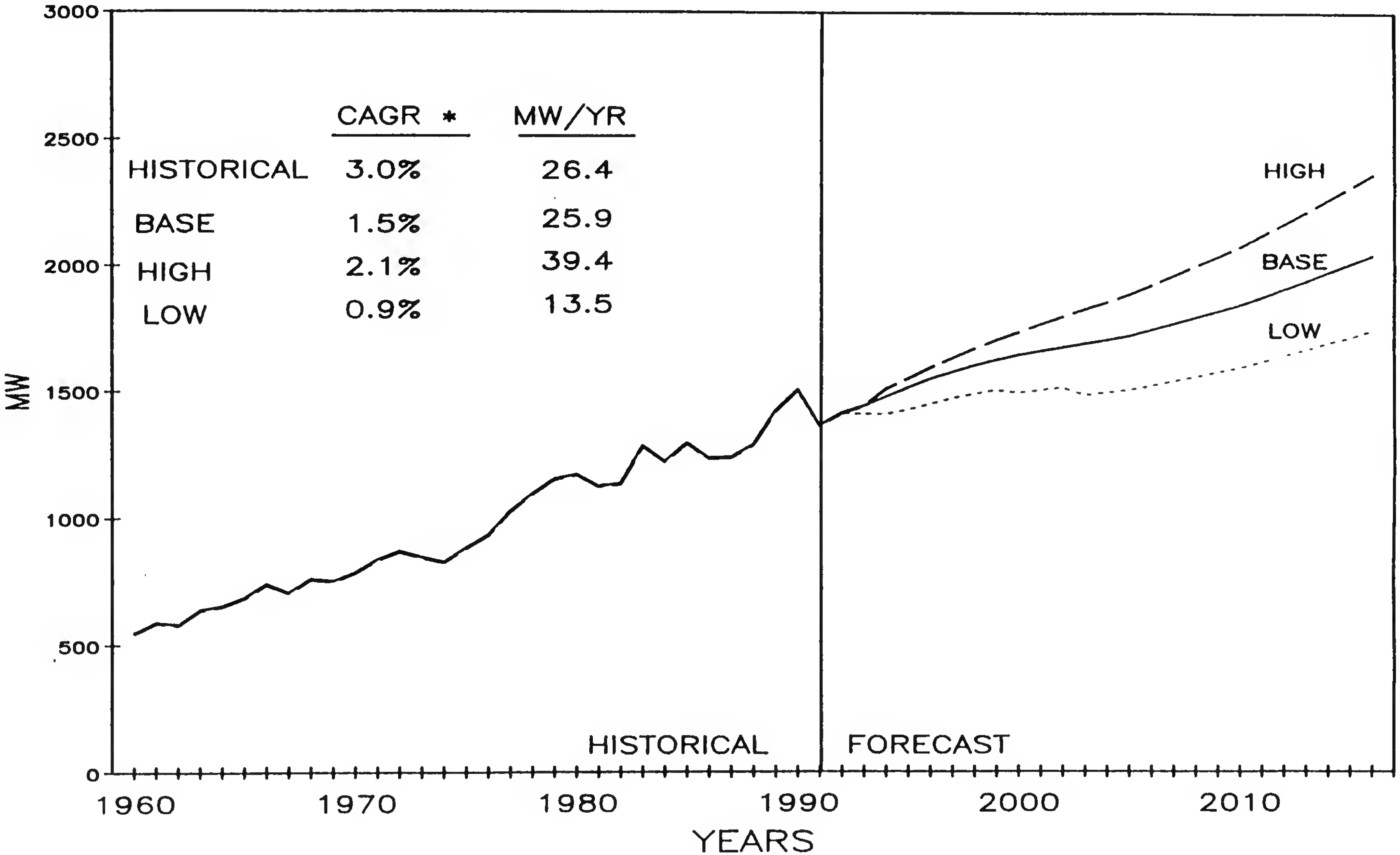
ILLUSTRATION 7
ENERGY FORECAST SCENARIOS



* COMPOUND ANNUAL GROWTH RATE

R93 OUTPUTS-BOOK, BOOK.WK1, ENERGY.CHT

ILLUSTRATION 8
PEAK FORECAST SCENARIOS



R93 OUTPUTS.BOOK, BOOK.WK1, PEAK.CHT

The Montana Power Company
Historical Firm Energy and Peak Load, in average MW and MW
1960-69, 1993 LEAST COST PLAN

CALENDAR YEAR

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL	YEAR	OPR
1960 ENERGY:	298	326	377	380	369	372	369	356	349	358	374	385	359		
PEAK:	454	483	500	471	476	466	485	462	451	480	533	545	545		
L.F.:	0.658	0.675	0.754	0.807	0.775	0.798	0.761	0.771	0.774	0.746	0.702	0.706	0.659		
1961 ENERGY:	378	373	375	374	361	372	361	375	351	377	399	419	376	1960-1961	369
PEAK:	513	493	490	473	466	493	474	484	471	512	559	585	585		545
L.F.:	0.737	0.757	0.765	0.791	0.775	0.755	0.762	0.775	0.745	0.736	0.714	0.716	0.643		
1962 ENERGY:	431	418	411	393	393	393	367	354	347	384	396	417	392	1961-1962	393
PEAK:	576	540	524	493	502	497	494	453	464	520	552	559	576		585
L.F.:	0.748	0.774	0.784	0.797	0.783	0.791	0.743	0.781	0.748	0.738	0.717	0.746	0.681		
1963 ENERGY:	457	418	408	395	376	364	372	376	369	392	416	454	399	1962-1963	390
PEAK:	601	554	514	518	489	489	499	493	478	524	601	635	635		601
L.F.:	0.76	0.755	0.794	0.763	0.769	0.744	0.745	0.763	0.772	0.748	0.692	0.715	0.628		
1964 ENERGY:	417	444	462	428	425	433	434	429	422	425	448	476	438	1963-1964	416
PEAK:	602	588	575	559	549	547	540	554	543	567	615	650	650		635
L.F.:	0.693	0.755	0.803	0.766	0.774	0.792	0.804	0.774	0.777	0.75	0.728	0.732	0.674		
1965 ENERGY:	468	469	470	459	444	451	452	453	467	470	488	512	469	1964-1965	450
PEAK:	627	632	601	578	567	569	574	591	612	600	654	683	683		650
L.F.:	0.746	0.742	0.782	0.794	0.783	0.793	0.787	0.766	0.763	0.783	0.746	0.75	0.687		
1968 ENERGY:	524	519	502	492	488	489	495	494	487	511	539	554	510	1965-1966	488
PEAK:	689	675	654	621	617	609	622	625	614	660	737	728	737		689
L.F.:	0.761	0.769	0.768	0.792	0.791	0.803	0.796	0.79	0.793	0.774	0.731	0.761	0.692		
1967 ENERGY:	555	558	557	526	507	511	438	390	376	370	389	424	466	1966-1967	525
PEAK:	703	697	699	663	651	626	655	508	491	492	566	621	703		737
L.F.:	0.789	0.801	0.797	0.793	0.779	0.816	0.669	0.768	0.766	0.752	0.687	0.683	0.663		
1968 ENERGY:	438	410	391	470	520	520	532	517	509	520	543	579	495	1967-1968	428
PEAK:	589	552	529	595	644	649	663	640	626	650	704	757	757		655
L.F.:	0.744	0.743	0.739	0.79	0.807	0.801	0.802	0.808	0.813	0.8	0.771	0.765	0.654		
1969 ENERGY:	602	583	560	527	520	518	520	521	520	529	543	567	542	1968-1969	543
PEAK:	748	698	712	655	647	642	656	643	640	683	699	731	748		757
L.F.:	0.805	0.835	0.787	0.805	0.804	0.807	0.793	0.81	0.813	0 775	0.777	0.776	0.725		

R93 OUTPUTS, LOADS

The Montana Power Company
Historical Firm Energy and Peak Load, in average MW and MW
1970-79, 1993 LEAST COST PLAN

CALENDAR YEAR

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL	YEAR	OPR
1970 ENERGY:	592	572	589	552	525	546	546	556	545	561	590	614	564	1969-1970	546
PEAK:	753	710	697	672	668	698	679	694	657	708	767	782	782		753
L.F.:	0.786	0.806	0.818	0.821	0.788	0.782	0.804	0.801	0.83	0.792	0.769	0.785	0.721		
1971 ENERGY:	620	603	595	569	562	577	452	469	446	555	614	664	561	1970-1971	578
PEAK:	810	739	723	684	681	720	588	590	635	755	776	834	834		810
L.F.:	0.765	0.816	0.823	0.832	0.825	0.801	0.769	0.795	0.702	0.735	0.791	0.796	0.673		
1972 ENERGY:	675	649	611	577	574	573	560	544	530	551	583	636	589	1971-1972	572
PEAK:	867	811	751	697	701	699	698	682	659	716	767	843	867		867
L.F.:	0.779	0.8	0.814	0.828	0.819	0.82	0.802	0.798	0.804	0.77	0.76	0.754	0.679		
1973 ENERGY:	631	605	568	556	546	562	577	571	544	558	606	605	578	1972-1973	573
PEAK:	843	779	714	687	712	706	723	720	666	739	696	772	843		843
L.F.:	0.749	0.777	0.796	0.809	0.767	0.796	0.798	0.793	0.817	0.755	0.871	0.784	0.686		
1974 ENERGY:	643	608	598	577	585	597	615	575	568	574	612	639	599	1973-1974	589
PEAK:	823	740	739	695	728	760	770	745	685	725	774	794	823		823
L.F.:	0.781	0.822	0.809	0.83	0.804	0.786	0.799	0.772	0.829	0.792	0.791	0.805	0.728		
1975 ENERGY:	649	659	611	585	567	571	597	577	560	599	630	665	606	1974-1975	602
PEAK:	808	849	752	742	706	713	792	755	686	738	840	880	880		849
L.F.:	0.803	0.776	0.813	0.788	0.803	0.801	0.754	0.764	0.816	0.812	0.75	0.756	0.689		
1976 ENERGY:	675	655	646	601	593	629	655	624	625	651	700	749	650	1975-1976	619
PEAK:	885	895	829	777	735	787	829	797	765	793	900	930	930		895
L.F.:	0.763	0.732	0.779	0.773	0.807	0.799	0.79	0.783	0.817	0.821	0.778	0.805	0.699		
1977 ENERGY:	782	703	691	660	648	676	589	653	649	648	742	799	687	1976-1977	680
PEAK:	960	856	847	816	794	849	755	788	768	851	985	1026	1026		960
L.F.:	0.815	0.821	0.818	0.809	0.816	0.796	0.78	0.829	0.845	0.761	0.753	0.779	0.67		
1978 ENERGY:	798	761	697	654	616	634	658	714	682	717	824	876	719	1977-1978	687
PEAK:	991	966	959	795	759	837	887	883	834	910	1034	1095	1095		1026
L.F.:	0.805	0.788	0.727	0.823	0.812	0.757	0.742	0.809	0.818	0.788	0.797	0.8	0.657		
1979 ENERGY:	934	850	783	688	689	710	742	727	725	750	824	837	772	1978-1979	760
PEAK:	1154	1064	952	842	870	882	951	948	845	913	1036	1056	1154		1154
L.F.:	0.809	0.799	0.822	0.817	0.792	0.805	0.78	0.767	0.858	0.821	0.795	0.793	0.669		

ILLUSTRATION 9
PAGE 3 OF 6

The Montana Power Company
Historical Firm Energy and Peak Load, in average MW and MW
1980-89, 1993 LEAST COST PLAN

	CALENDAR YEAR													Operating	Year
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann	Year	Opr
1980 ENERGY:	923	859	840	729	681	681	669	663	655	682	736	818	745	1979-1980	777
PEAK:	1171	1109	1089	925	871	878	876	860	777	868	932	1081	1171		1171
L.F.:	0.788	0.775	0.771	0.788	0.782	0.776	0.764	0.771	0.843	0.786	0.79	0.757	0.636		
1981 ENERGY:	776	806	771	715	674	682	746	741	716	738	772	822	746	1980-1981	721
PEAK:	960	1124	916	897	875	895	950	920	884	943	987	1051	1124		1124
L.F.:	0.808	0.717	0.842	0.797	0.77	0.762	0.785	0.805	0.81	0.783	0 782	0.782	0.664		
1982 ENERGY:	887	831	774	720	673	678	689	720	703	768	860	892	766	1981-1982	758
PEAK:	1135	1114	950	922	859	871	922	933	870	950	1077	1129	1135		1135
L.F.:	0.781	0.746	0.815	0.781	0.783	0.778	0.747	0.772	0.808	0.808	0.799	0.79	0.675		
1983 ENERGY:	839	803	801	750	747	776	728	761	721	740	792	974	786	1982-1983	779
PEAK:	1038	1038	954	925	898	978	939	978	901	884	1093	1283	1283		1129
L.F.:	0.808	0.774	0.84	0.811	0.832	0.793	0.775	0.778	0.8	0.837	0.725	0.759	0.613		
1984 ENERGY:	871	811	795	762	737	770	812	805	767	824	873	966	816	1983-1984	789
PEAK:	1221	1001	975	972	914	1028	1019	1013	1020	1083	1116	1221	1221		1283
L.F.:	0.713	0.81	0.815	0.784	0.806	0.749	0.797	0.795	0.752	0.761	0.782	0.791	0.668		
1985 ENERGY:	950	930	842	735	754	757	852	772	779	804	952	939	839	1984-1985	835
PEAK:	1249	1295	1136	909	962	1008	1123	1004	986	1101	1272	1289	1295		1295
L.F.:	0.761	0.718	0.741	0.809	0.784	0.751	0.759	0.769	0.79	0.73	0.748	0.728	0.648		
1986 ENERGY:	902	919	786	739	758	793	831	842	806	819	921	947	838	1985-1986	833
PEAK:	1134	1170	971	951	990	1061	1033	1078	972	1019	1233	1187	1233		1289
L.F.:	0.795	0.785	0.809	0.777	0.764	0.747	0.804	0.781	0.829	0.804	0.747	0.798	0.68		
1987 ENERGY:	932	880	867	793	821	842	847	839	819	841	900	976	863	1986-1987	858
PEAK:	1236	1189	1068	976	1043	1059	1060	1052	1006	1058	1140	1237	1237		1236
L.F.:	0.754	0.74	0.812	0.813	0.787	0.795	0.799	0.798	0.814	0.795	0.789	0.789	0.698		
1988 ENERGY:	1012	969	905	821	850	919	917	877	848	818	918	965	902	1987-1988	892
PEAK:	1287	1247	1069	1018	1063	1178	1163	1115	1042	1070	1155	1211	1287		1287
L.F.:	0.786	0.777	0.847	0.806	0.8	0.78	0.788	0.787	0.814	0.764	0.795	0.797	0.701		
1989 ENERGY:	979	1083	971	868	847	893	953	902	846	884	940	1038	934	1988 1989	915
PEAK:	1303	1420	1303	1067	1006	1114	1177	1131	1004	1097	1177	1370	1420		1420
L.F.:	0.751	0.763	0.745	0.813	0.842	0.802	0.81	0.798	0.843	0.806	0.799	0.758	0.658		

ILLUSTRATION 9
PAGE 4 OF 6

The Montana Power Company
Historical and Forecast Firm Energy and Peak Load, in average MW and MW
1990-99, 1993 LEAST COST PLAN

	CALENDAR YEAR													Operating	Year
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann	Year	Opr
1990 ENERGY:	1004	984	904	872	857	922	964	914	876	913	946	1098	938	1989-1990	926
PEAK:	1300	1322	1189	1106	1064	1188	1190	1164	1144	1101	1196	1504	1504		1370
L.F.:	0.772	0.744	0.76	0.788	0.805	0.776	0.81	0.785	0.766	0.829	0.791	0.73	0.624		
1991 ENERGY:	1070	945	938	894	847	883	965	967	885	939	1026	1041	950	1990-1991	941
PEAK:	1362	1168	1215	1077	1092	1100	1234	1203	1074	1267	1228	1253	1362		1504
L.F.:	0.786	0.81	0.772	0.83	0.776	0.803	0.782	0.804	0.824	0.741	0.836	0.831	0.698		
1992 ENERGY:	1086	1026	951	898	895	914	961	957	900	945	997	1073	966	1991-1992	966
PEAK:	1412	1302	1208	1112	1133	1191	1231	1190	1123	1176	1284	1374	1412		1412
L.F.:	0.769	0.788	0.787	0.808	0.79	0.767	0.781	0.804	0.801	0.804	0.776	0.781	0.684		
1993 ENERGY:	1106	1042	966	912	909	928	976	971	914	960	1012	1090	982	1992-1993	975
PEAK:	1439	1327	1230	1133	1152	1210	1251	1209	1141	1199	1308	1400	1439		1439
L.F.:	0.769	0.785	0.785	0.805	0.789	0.767	0.78	0.803	0.801	0.801	0.774	0.779	0.682		
1994 ENERGY:	1135	1068	990	935	932	951	1002	995	937	984	1037	1118	1007	1993-1994	995
PEAK:	1475	1361	1262	1162	1183	1242	1285	1242	1171	1229	1341	1435	1475		1475
L.F.:	0.769	0.785	0.784	0.805	0.788	0.766	0.78	0.801	0.8	0.801	0.773	0.779	0.683		
1995 ENERGY:	1164	1096	1016	959	955	976	1029	1021	961	1009	1064	1147	1033	1994-1995	1020
PEAK:	1511	1394	1292	1190	1215	1276	1319	1276	1203	1259	1374	1470	1511		1511
L.F.:	0.77	0.786	0.786	0.806	0.786	0.765	0.78	0.8	0.799	0.801	0.774	0.78	0.684		
1996 ENERGY:	1192	1122	1040	982	979	999	1055	1046	984	1034	1090	1174	1058	1995-1996	1045
PEAK:	1546	1426	1322	1217	1245	1308	1353	1308	1233	1288	1405	1504	1546		1546
L.F.:	0.771	0.787	0.787	0.807	0.786	0.764	0.78	0.8	0.798	0.803	0.776	0.781	0.684		
1997 ENERGY:	1214	1143	1060	1000	997	1018	1076	1065	1003	1053	1110	1197	1078	1996-1997	1068
PEAK:	1573	1451	1345	1239	1270	1335	1380	1334	1258	1311	1430	1531	1573		1573
L.F.:	0.772	0.788	0.788	0.807	0.785	0.763	0.78	0.798	0.797	0.803	0.776	0.782	0.685		
1998 ENERGY:	1235	1162	1077	1017	1014	1035	1095	1083	1019	1071	1129	1217	1096	1997-1998	1087
PEAK:	1599	1475	1368	1259	1293	1358	1404	1358	1260	1332	1454	1556	1599		1599
L.F.:	0.772	0.788	0.787	0.808	0.784	0.762	0.78	0.797	0.796	0.804	0.776	0.782	0.685		
1999 ENERGY:	1252	1178	1092	1031	1027	1049	1110	1098	1033	1085	1144	1233	1111	1998-1999	1104
PEAK:	1621	1495	1386	1276	1311	1377	1424	1376	1298	1350	1474	1577	1621		1621
L.F.:	0.772	0.788	0.788	0.808	0.783	0.762	0.779	0.798	0.796	0.804	0.776	0.782	0.685		

ILLUSTRATION 9
PAGE 5 OF 6

Tha Montana Power Company
Foracast Firm Energy and Peak Load, in average MW and MW
2000-2009, 1993 LEAST COST PLAN

	CALENDAR YEAR													Operating	Year
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann	Year	Opr
2000 ENERGY:	1267	1190	1103	1042	1038	1060	1122	1109	1044	1097	1156	1248	1123	1999-2000	1117
PEAK:	1640	1512	1402	1291	1325	1392	1439	1392	1312	1366	1491	1595	1640		1640
L.F.:	0.773	0.787	0.787	0.807	0.783	0.781	0.78	0.797	0.796	0.803	0.775	0.782	0.685		
2001 ENERGY:	1280	1202	1114	1052	1048	1070	1134	1120	1054	1107	1167	1260	1134	2000-2001	1129
PEAK:	1658	1527	1416	1304	1339	1407	1455	1407	1327	1380	1506	1611	1656		1656
L.F.:	0.773	0.787	0.787	0.807	0.783	0.76	0.779	0.796	0.794	0.802	0.775	0.782	0.685		
2002 ENERGY:	1292	1213	1124	1061	1058	1080	1144	1130	1063	1117	1178	1271	1144	2001-2002	1139
PEAK:	1671	1541	1429	1316	1351	1420	1468	1419	1338	1392	1519	1626	1671		1671
L.F.:	0.773	0.787	0.787	0.806	0.783	0.761	0.779	0.796	0.794	0.802	0.776	0.782	0.685		
2003 ENERGY:	1303	1223	1134	1070	1067	1089	1155	1140	1073	1127	1188	1282	1154	2002-2003	1149
PEAK:	1685	1554	1441	1327	1364	1433	1482	1433	1351	1404	1532	1639	1685		1685
L.F.:	0.773	0.787	0.787	0.806	0.782	0.76	0.779	0.796	0.794	0.803	0.775	0.782	0.685		
2004 ENERGY:	1315	1234	1144	1080	1076	1099	1165	1150	1082	1137	1198	1293	1164	2003-2004	1159
PEAK:	1700	1568	1454	1338	1376	1446	1495	1445	1363	1416	1546	1654	1700		1700
L.F.:	0.774	0.787	0.787	0.807	0.782	0.76	0.779	0.796	0.794	0.803	0.775	0.782	0.685		
2005 ENERGY:	1328	1245	1154	1090	1086	1109	1177	1161	1092	1147	1210	1305	1175	2004-2005	1170
PEAK:	1716	1583	1468	1351	1391	1461	1510	1460	1377	1430	1560	1670	1716		1716
L.F.:	0.774	0.786	0.788	0.607	0.781	0.759	0.779	0.795	0.793	0.802	0.776	0.781	0.685		
2006 ENERGY:	1346	1260	1168	1103	1099	1122	1192	1175	1105	1161	1224	1321	1189	2005-2006	1183
PEAK:	1740	1604	1488	1370	1409	1480	1530	1479	1395	1449	1582	1692	1740		1740
L.F.:	0.774	0.786	0.785	0.805	0.78	0.758	0.779	0.794	0.792	0.801	0.774	0.781	0.683		
2007 ENERGY:	1364	1275	1182	1116	1112	1135	1207	1188	1118	1175	1238	1336	1203	2006-2007	1197
PEAK:	1763	1626	1508	1388	1427	1499	1550	1498	1413	1469	1603	1715	1763		1763
L.F.:	0.774	0.784	0.784	0.804	0.779	0.757	0.779	0.793	0.791	0.8	0.772	0.779	0.682		
2008 ENERGY:	1383	1291	1197	1130	1126	1149	1223	1203	1132	1189	1254	1353	1219	2007-2008	1212
PEAK:	1788	1649	1529	1407	1446	1519	1571	1519	1432	1489	1625	1739	1788		1788
L.F.:	0.773	0.783	0.783	0.803	0.779	0.756	0.778	0.792	0.791	0.799	0.772	0.778	0.682		
2009 ENERGY:	1402	1307	1211	1144	1140	1164	1239	1218	1146	1204	1269	1370	1234	2008-2009	1227
PEAK:	1812	1671	1550	1427	1465	1539	1592	1539	1451	1510	1648	1763	1812		1812
L.F.:	0.774	0.782	0.781	0.802	0.778	0.756	0.778	0.791	0.79	0.797	0.77	0.777	0.681		

The Montana Power Company
Forecast Firm Energy and Peak Load, in average MW and MW
2010-2016, 1993 LEAST COST PLAN

	CALENDAR YEAR													Operating	Year
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann	Year	Opr
2010 ENERGY:	1421	1323	1226	1157	1154	1178	1255	1233	1160	1218	1285	1386	1249	2009-2010	1242
PEAK:	1837	1694	1571	1446	1485	1560	1613	1559	1470	1530	1670	1787	1837		1837
L.F.:	0.774	0.781	0.78	0.8	0.777	0.755	0.778	0.791	0.789	0.796	0.769	0.776	0.68		
2011 ENERGY:	1444	1339	1242	1172	1168	1193	1272	1248	1175	1234	1301	1405	1266	2010-2011	1258
PEAK:	1868	1722	1597	1470	1505	1582	1635	1581	1491	1556	1698	1817	1868		1868
L.F.:	0.773	0.778	0.778	0.797	0.776	0.754	0.778	0.789	0.788	0.793	0.766	0.773	0.678		
2012 ENERGY:	1469	1358	1259	1188	1184	1209	1290	1265	1191	1251	1319	1425	1284	2011-2012	1275
PEAK:	1901	1753	1625	1496	1527	1605	1659	1604	1513	1583	1728	1849	1901		1901
L.F.:	0.773	0.775	0.775	0.794	0.775	0.753	0.778	0.789	0.787	0.79	0.763	0.771	0.675		
2013 ENERGY:	1493	1376	1276	1204	1200	1225	1309	1283	1207	1268	1337	1445	1301	2012-2013	1293
PEAK:	1932	1782	1652	1521	1550	1629	1684	1628	1536	1610	1757	1880	1932		1932
L.F.:	0.773	0.772	0.772	0.792	0.774	0.752	0.777	0.788	0.786	0.788	0.761	0.769	0.673		
2014 ENERGY:	1519	1396	1294	1221	1217	1243	1329	1301	1224	1286	1356	1466	1321	2013-2014	1312
PEAK:	1967	1814	1682	1548	1575	1654	1711	1654	1560	1639	1788	1913	1967		1967
L.F.:	0.772	0.77	0.769	0.789	0.773	0.752	0.777	0.787	0.785	0.785	0.758	0.766	0.672		
2015 ENERGY:	1544	1414	1311	1238	1233	1259	1348	1318	1240	1303	1374	1486	1339	2014-2015	1330
PEAK:	2000	1844	1710	1574	1598	1679	1736	1678	1583	1666	1818	1946	2000		2000
L.F.:	0.772	0.767	0.767	0.787	0.772	0.75	0.776	0.785	0.783	0.782	0.756	0.764	0.669		
2016 ENERGY:	1569	1434	1329	1255	1250	1277	1368	1336	1257	1321	1392	1507	1357	2015-2016	1349
PEAK:	2033	1875	1738	1601	1622	1704	1762	1704	1607	1694	1848	1978	2033		2033
L.F.:	0.772	0.765	0.765	0.784	0.771	0.749	0.776	0.784	0.782	0.78	0.753	0.762	0.667		

* Forecast starts in January 1992

kmb>R93#2>ILLUS10.WK1

Illustration 10

Firm Utility Sales

Name	MW Peak	Average MW Energy	Effective
PacifiCorp Sale	15	15	01/90 - 12/92
" "	10	10	01/93 - 12/95
Black Hills Power & Light Sale	10	0	06/89 - 09/89
" "	15	0	10/89 - 09/90
" "	20	1	10/90 - 09/91
" "	25	1	10/91 - 03/92
" "	30	2	04/92 - 09/93
WWP Off-Peak Sale	0	36	01/91 - 12/93
" "	0	27	01/94 - 12/94
BPA Sale	0	(*) 80	09/93 - 04/96

(*) Delivery of sale is September through April and this average number could change based on contract flexibility.

ILLUSTRATION 11

EXISTING THERMAL RESOURCE PLANNED CAPABILITIES

Plant Name	Number of Units	Commercial Operation Date	Peak Capability (MW)	Annual Energy (AMW)*	Fuel	Nameplate MW(2)
UTILITY RESOURCE						
JE Corette-Billings (1)	1	09/01/68	160	122	Coal, Natural Gas Start-up	163
Colstrip Unit #1 (1)	1	11/15/75	159	125	Coal, Propane Start-up	333
Colstrip Unit #2 (1)	1	08/20/76	160	125	Coal, Propane Start-up	333
Colstrip Unit #3 (1)	1	01/10/84	218	185 (5)	Coal, #2 Fuel Oil Start-up	718
			697	557		

The following resources provides stand-by service for Yellowstone National Park.

Plant Name	Number of Units	Commercial Operation Date	Peak Capability (MW)	Annual Energy (AMW)*	Fuel	Nameplate MW(2)
Lake Diesel-YNP (3)	1	07/10/67	2.75	---	Diesel	---
Old Faithful Diesel-YNP (4)	2	09/01/79	2	---	Diesel	---
			4.75			

Notes:

* After Maintenance

(1) Ownership

		OWNERSHIP PERCENT				
		MPC	PUGET	PACIFICORP	PGE	WWP
Corette		100				
Colstrip Unit #1		50	50			
Colstrip Unit #2		50	50			
Colstrip Unit #3		30	25	10	20	15

(2) Nameplate for total plant before plant use.

(3) Available in summer months only, provides emergency power in event of line outages.

(4) Provides emergency power in event of line outages.

(5) Includes reciprocal sharing agreement with Colstrip Unit #4.

ILLUSTRATION 12

EXISTING HYDRO RESOURCE PLANNED CAPABILITIES

Plant Name	Storage	Number of Units	Installed	RFP January Peak Capability MW (4)	BPLAN January Peak Capability MW (4)	Annual Critical Water AMW*	Nameplate MW (3)
Flint Creek (5)	Y	2	1901			1	1.1
Milltown	N	4	1906	2	2	2	4.0
		1	1926				
Mystic	Y	2	1925	5	11	6	12.5
Hebgen (1)	Y	0	1915	0	0	0	
Madison	Y	4	1906	8	5	7	9.0
Hauser	Y	5	1907	17	13	12	17.0
		1	1914				
Holter	Y	4	1918	50	27	24	48.0
Black Eagle	N	3	1927	17	14	14	21.0
Rainbow	N	6	1910	33	28	29	41.6
		2	1917				
Cochrane	N	2	1958	32	33	22	60.0
Ryan	N	4	1915	60	60	41	48.0
		2	1916				
Morony	N	2	1930	47	22	25	50.0
Kerr (2)	Y	1	1938				
		1	1949	185	180	119	168.0
		1	1954				
Thompson Falls	N	2	1915				
		2	1916	33	40	35	30.0
		2	1917				
TOTAL		53		489	435	337 (6)	510.2
Median Water Capability				489	489	385	

Canyon Ferry - 47,500 acre-feet of storage owned by Montana Power Company in this U.S. Bureau of Reclamation Reservoir, which contains a total usable storage capacity of 1,512,000 acre-feet. The operation of Canyon Ferry's storage is coordinated with MPC's downstream projects by the Missouri River Coordination Agreement.

Hungry Horse - Zero storage owned by MPC, however, this U.S. Bureau of Reclamation Reservoir contains 3,161,000 acre-feet of usable stoarge. The operation of Hungry Horse's storage is coordinated with MPC's downstream projects by the Pacific Northwest Coordination Agreement.

NOTES:

* Before maintenance
(1) Storage only, 373,500 acre-feet
(2) 1,219,000 acre-feet of storage
(3) Before station use.
(4) After maintenance
(5) FERC has accepted MPC's surrender of the license and granted a new license to operate the project by Granite County. The project is currently inoperable.
(6) 335 average MW after maintenance.

ILLUSTRATION 13

EXISTING LONG TERM CONTRACT RESOURCES

Contract	Ending Date	(Jan) Winter Capactiy MW	(Aug) Summer Capacity MW	Annual Energy AMW
BPA Peak for Energy Exchange	06/30/01	100	100	-29
WNP #1	06/30/96	79	79	67
(1) Idaho Power Exchange	12/31/97	50	-50	0
Idaho Peak Puchase	3/31/96	75	25	50
Basin Electric	3/31/95	0	0	up to 75
Existing QF	Various	45	44	38
(2) New QF; Billings Generation Inc. (BGI)	2029	52	52	47

EXISTING INTERRUPTIBLE LOAD

Name	Maximum MW	Estimated Annual Energy aMW
Rhone-Poulenc Basic Chemicals	64	3

Notes

(1) Seasonally differentiated contract specifies that MPC will receive from IPC 50 MW of energy and capacity for 90 days during the winter. MPC delivers to IPC an average of 75 MW for 60 days during the summer.

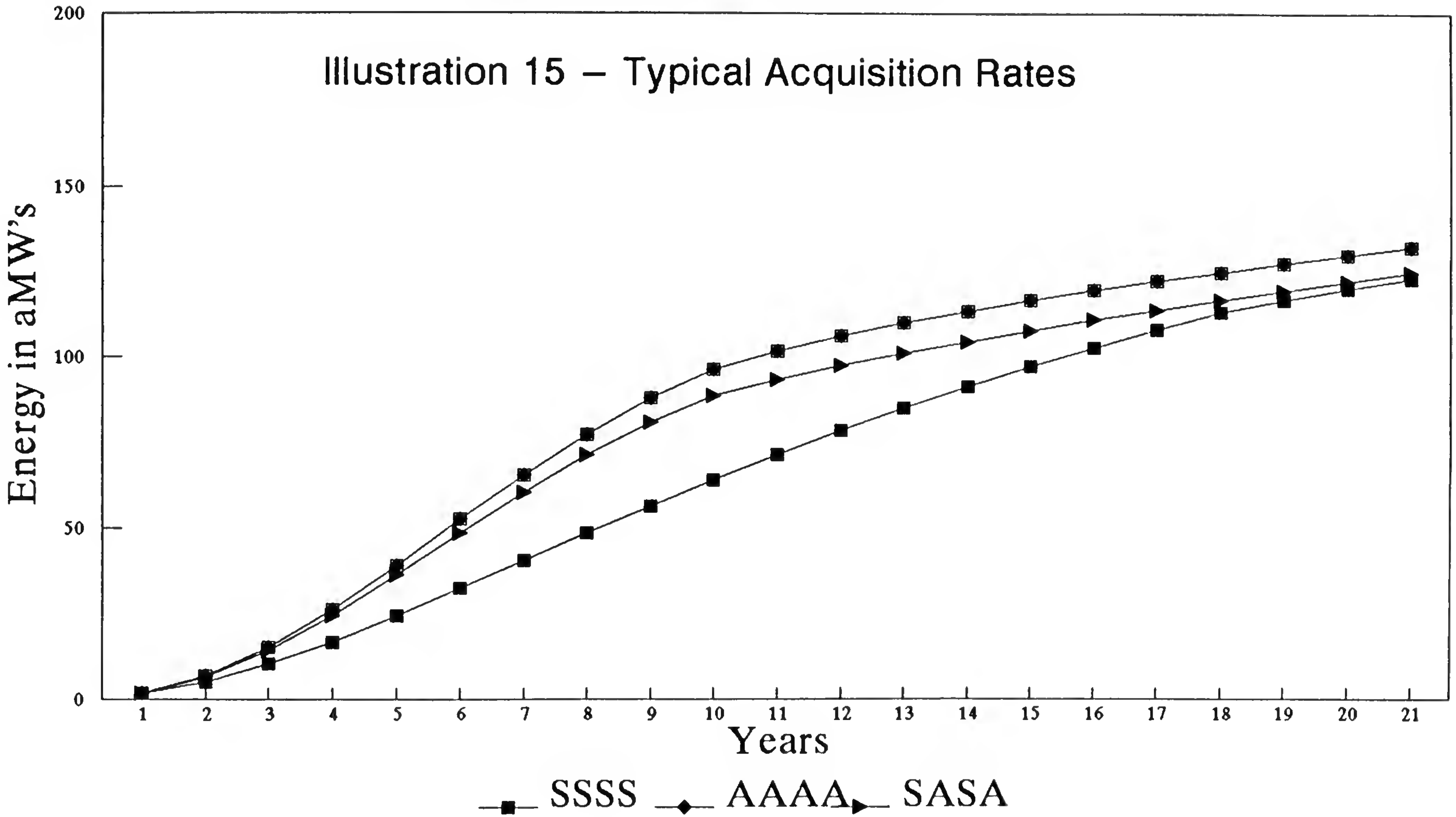
(2) Represents BGI contract starting in mid-1995.

ILLUSTRATION 14

Montana Power Company
Qualifying Facilities

	Hydro		Wind		Thermal		Total	
Year	Peak MW	Energy MWa	Peak MW	Energy MWa	Peak MW	Energy MWa	Peak MW	Energy MWa
1993-94	9.93	8.63	0.11	0.11	35.00	29.77	45.04	38.51
1994-95	9.93	8.63	0.11	0.11	35.00	29.77	45.04	38.51
1995-96	9.93	8.63	0.11	0.11	35.00	29.77	45.04	38.51
1996-97	9.93	8.63	0.11	0.11	87.00	76.57	97.04	85.31
1997-98	9.93	8.63	0.11	0.11	87.00	76.57	97.04	85.31
1998-99	9.93	8.63	0.11	0.11	87.00	76.57	97.04	85.31
1999-00	9.93	8.63	0.11	0.11	87.00	76.57	97.04	85.31
2000-01	9.93	8.63	0.11	0.11	87.00	76.57	97.04	85.31
2001-02	9.93	8.63	0.11	0.11	87.00	76.57	97.04	85.31
2002-03	9.93	8.63	0.11	0.11	87.00	76.57	97.04	85.31
Monthly	1993-94							
Jan	9.93	6.12	0.11	0.11	35.00	29.75	45.04	35.97
Feb	9.65	6.37	0.11	0.11	35.00	29.75	44.76	36.24
Mar	12.31	8.78	0.12	0.12	35.00	29.75	47.43	38.64
Apr	13.29	11.65	0.15	0.15	35.04	29.79	48.48	41.59
May	13.19	11.65	0.09	0.09	35.04	29.79	48.32	41.53
Jun	13.16	11.63	0.10	0.10	35.04	29.79	48.30	41.52
Jul	11.14	9.60	0.08	0.08	35.04	29.79	46.26	39.47
Aug	8.64	6.39	0.08	0.08	35.04	29.79	43.76	36.26
Sep	10.27	8.09	0.11	0.11	35.04	29.79	45.42	37.99
Oct	12.33	9.19	0.18	0.18	35.04	29.79	47.55	39.16
Nov	11.03	7.71	0.12	0.12	35.00	29.75	46.15	37.58
Dec	10.25	6.28	0.12	0.12	35.00	29.75	45.37	36.15
Monthly	1995							
Jan	9.93	6.12	0.11	0.11	35.00	29.75	45.04	35.97
Feb	9.65	6.37	0.11	0.11	35.00	29.75	44.76	36.24
Mar	12.31	8.78	0.12	0.12	35.00	29.75	47.43	38.64
Apr	13.29	11.65	0.15	0.15	35.04	29.79	48.48	41.59
May	13.19	11.65	0.09	0.09	35.04	29.79	48.32	41.53
Jun	13.16	11.63	0.10	0.10	87.04	76.59	100.30	88.32
Jul	11.14	9.60	0.08	0.08	87.04	76.59	98.26	86.27
Aug	8.64	6.39	0.08	0.08	87.04	76.59	95.76	83.06
Sep	10.27	8.09	0.11	0.11	87.04	76.59	97.42	84.79
Oct	12.33	9.19	0.18	0.18	87.04	76.59	99.55	85.96
Nov	11.03	7.71	0.12	0.12	87.00	76.55	98.15	84.38
Dec	10.25	6.28	0.12	0.12	87.00	76.55	97.37	82.95
Monthly	1996-							
Jan	9.93	6.12	0.11	0.11	87.00	76.55	97.04	82.77
Feb	9.65	6.37	0.11	0.11	87.00	76.55	96.76	83.04
Mar	12.31	8.78	0.12	0.12	87.00	76.55	99.43	85.44
Apr	13.29	11.65	0.15	0.15	87.04	76.59	100.48	88.39
May	13.19	11.65	0.09	0.09	87.04	76.59	100.32	88.33
Jun	13.16	11.63	0.10	0.10	87.04	76.59	100.30	88.32
Jul	11.14	9.60	0.08	0.08	87.04	76.59	98.26	86.27
Aug	8.64	6.39	0.08	0.08	87.04	76.59	95.76	83.06
Sep	10.27	8.09	0.11	0.11	87.04	76.59	97.42	84.79
Oct	12.33	9.19	0.18	0.18	87.04	76.59	99.55	85.96
Nov	11.03	7.71	0.12	0.12	87.00	76.55	98.15	84.38
Dec	10.25	6.28	0.12	0.12	87.00	76.55	97.37	82.95

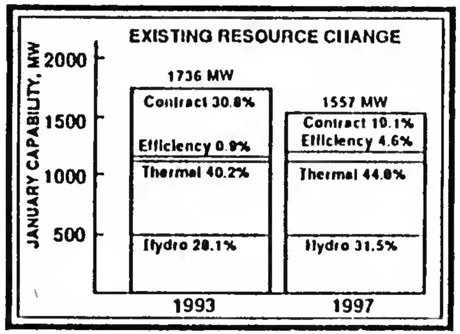
DEMAND–SIDE MANAGEMENT



Electricity for the Future

Every electric utility must plan to have enough electricity to meet the needs of more customers. Montana Power faces some interesting challenges. Montana's electric needs are growing slowly but steadily, yet some of our traditional sources of electricity will be unavailable beginning in 1996. How we will replace them and gain new sources to meet new demands are major planning topics.

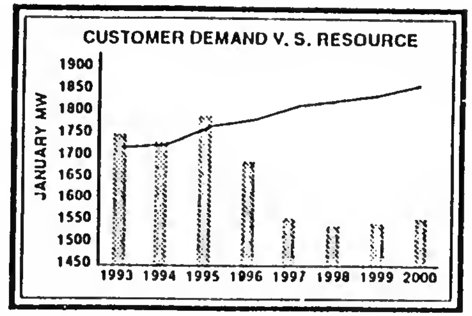
Without new resources, total electricity available to MPC customers would decline about 10 percent, or 179,000 kilowatts. That's because power we've bought or traded for with other utilities no longer will be available. The first chart shows MPC's sources of electricity in 1993 and what they would be in 1997. *(Thermal is dominated by MPC's coal-fueled generation in Colstrip and Billings; hydro comes from dams on both sides of the Continental Divide; Efficiency Plus represents MPC-assisted conservation).*



The second chart shows how customer demand - - - under a middle-of-the-road projection - - - would outstrip supply if nothing were done. By 1997, customers would be demanding 233,000 more kilowatts than we'd have available then. That's 15,000 more kilowatts than MPC's share of Colstrip 3 and roughly the amount used in the Butte area during peak cold weather.

So, how do we make certain there's enough electricity to go around? That's a question we've been asking ourselves and, with the help of Montanans interested and knowledgable in resource planning (the Conservation and Least-Cost Planning Committee with representatives of groups listed on the back side of this brochure), a process was developed to assist in our resource decisions. The main criteria for future resources include:

1. Cost of resource.
2. Fairness to customers and investors.
3. Environmental considerations.
4. Risk and reliability.



In 1991, MPC asked for proposals to supply the extra power needed beginning in 1996. The response - - - which exceeded MPC's need - - - was 6,000,000 kilowatts. For several months, those proposals were evaluated and the field was narrowed down to a group of the best resources comprising those proposed by nonutility producers, MPC and power from other utilities. Here's a list of resources that satisfy the criteria:

Proposed Supplies

MW[1]	SUPPLIER	TYPE OF RESOURCE	LOCATION
92	Westmoreland Energy	Natural gas turbine	Hardin
5	Continental Hydro	Hydroelectric reservoir	Tiber Reservoir
38	Stone Container	Natural gas turbine	Missoula
15	Stone Container	Pressure reduction	Missoula
68	LS Power/Conoco	Coke fuel, F.W. Bird Plant	Billings
50-76	Western utility	Seasonal power exchange	Outside Montana
98	Basin Electric	Seasonal power purchase	N. Dakota
43	Montana Power	Ryan dam upgrade	Great Falls
41	Montana Power	Thompson Falls upgrade	Thompson Falls
60	Montana Power	F. W. Bird upgrade	Billings
116	MPC & customers	Efficiency plus	MPC electric service territory

[1]MEGAWATTS (1000 KILOWATTS)

May we hear from you?

In making final decisions about which resources to choose, we need your comments. There are two ways you can participate. First, you are invited to attend one of the listed public meetings, where we'll explain the resource planning process and welcome your comments. Second, you may fill out this brief questionnaire and return it with your payment. We would like to hear from you.

In deciding which resources to use, how much weight should these factors be given?

Factor	Heavy	Medium	Light	None
Price	___	___	___	___
Environmental impact	___	___	___	___
Located in Montana	___	___	___	___
Reliability of service	___	___	___	___
Local community impact	___	___	___	___
Other___________	___	___	___	___
Other___________	___	___	___	___

To help us categorize and compile the questionnaire results, please fill out the following information. Your answers are confidential and will be used only as statistics.

Age:	Under 30 _____	30-50 _____ Over 50 ______
Home:	Farm/ranch/rural ____	Town/city/urban _____
Montana resident:	Less than 5 years ___	5-10 years ___
	10-20 years ___	20 years or more ___

(Committee included representatives from: Montana Department of Natural Resources and Conservation, Montana Environmental Information Center, Northern Plains Resource Council, Northwest Power Planning Council, District XI Human Resources Council, Montana Power Company and Industrial Customers group.

PUBLIC MEETINGS

Bozeman
Nov. 10, 7:00 p.m.
Holiday Inn

Butte
Nov. 11, 7:00 p.m.
Copper King Inn

Helena
Nov. 12, 7:00 p.m.
Colonial Inn

Havre
Nov. 17, 7:00 p.m.
Duck Inn

Great Falls
Nov. 18, 7:00 p.m.
Heritage Inn

Missoula
Nov. 19, 7:00 p.m.
Park Holiday

Billings
Nov. 24, 7:00 p.m.
Holiday Inn

ILLUSTRATION 17

12/10/92 **Bill Insert Questionnaire Summary**

Prepared by: Kathy Bauer

Ttl rcvd to date: 3678
Ttl input to date: 3678

	Heavy Weight	Percent	Medium Weight	Percent	Low Weight	Percent	No Weight	Percent	No Response	Percent
Price	1944	52.85%	1388	37.08%	201	5.46%	30	0.82%	117	3.18%
Environmental Impact	2111	57.40%	1084	29.47%	307	8.35%	63	1.71%	113	3.07%
Located In Montana	1428	38.83%	1203	32.71%	627	17.05%	247	6.72%	173	4.70%
Reliability	2567	69.79%	879	23.90%	93	2.53%	12	0.33%	127	3.45%
Local Impact	1465	39.83%	1471	39.99%	412	11.20%	90	2.45%	240	6.53%

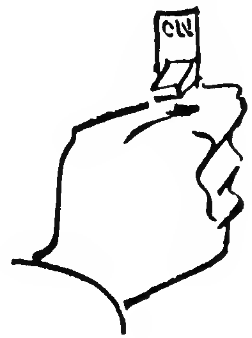
Age	#	Percent
Age Under 30	251	6.82%
Age 30 50	1548	42.09%
Age Over 50	1773	48.21%
No response	106	2.88%

Home	#	Percent
Home Farm/Ranch/Rural	724	19.68%
Home Town/City/Urban	2747	74.69%
No response	207	5.63%

MT Resident	#	Percent
Resident Less than 5 Yrs	416	11.31%
Resident 5-10 Yrs	281	7.64%
Resident 10 20 Yrs	556	15 12%
Resident 20 Yrs or more	2352	63.95%
No response	73	1.98%

Reporting future resource survey results

For as long as most of us remember, when you and I wanted light or toast or soup, we flipped the correct switch or acti-



vated the proper appliance in the prescribed manner. We haven't worried much about what was at the other end of those copper wires leading to our homes.

With that in mind, it was particularly pleasing for me to learn that nearly 3,700 MPC customers responded to the "Electricity for the Future" questionnaire included in your bills back in October and November. In essence, the survey asked what weight you would assign to five factors used in selecting future sources of electricity. The chart summarizes the response. The people assigned to making the decisions about future resources thank the folks who responded to the survey for sharing their points of view. Also to be thanked are the nearly 150 people who attended public meetings and others who submitted written comments.

In general, at the public meetings people seemed in favor of the list of resources submitted by Montana Power, as well as showing a strong positive attitude toward MPC's Efficiency Plus program. Most of the comments and concerns tended to cluster around the same topics shown in the survey - - that is, cost, rates, the environment, conservation and reliability.

The information MPC gained through the public process will help us select the resources from our short list and influence our future planning efforts.

HOW CUSTOMERS WEIGHT POWER SOURCE SELECTION FACTORS

Factors	Weight(%)*				
	heavy	medium	light	none	no response
Price	53	38	5	1	3
Environmental Impact	57	29	8	2	3
Reliability	70	24	3	0	3
Located in MT	39	33	17	7	5
Local Impact	40	40	11	2	7

*Horizontal columns totaling more or less than 100% reflect rounding numbers off to the nearest whole number.

ILLUSTRATION 19

First Screen Resources, Ratio 1

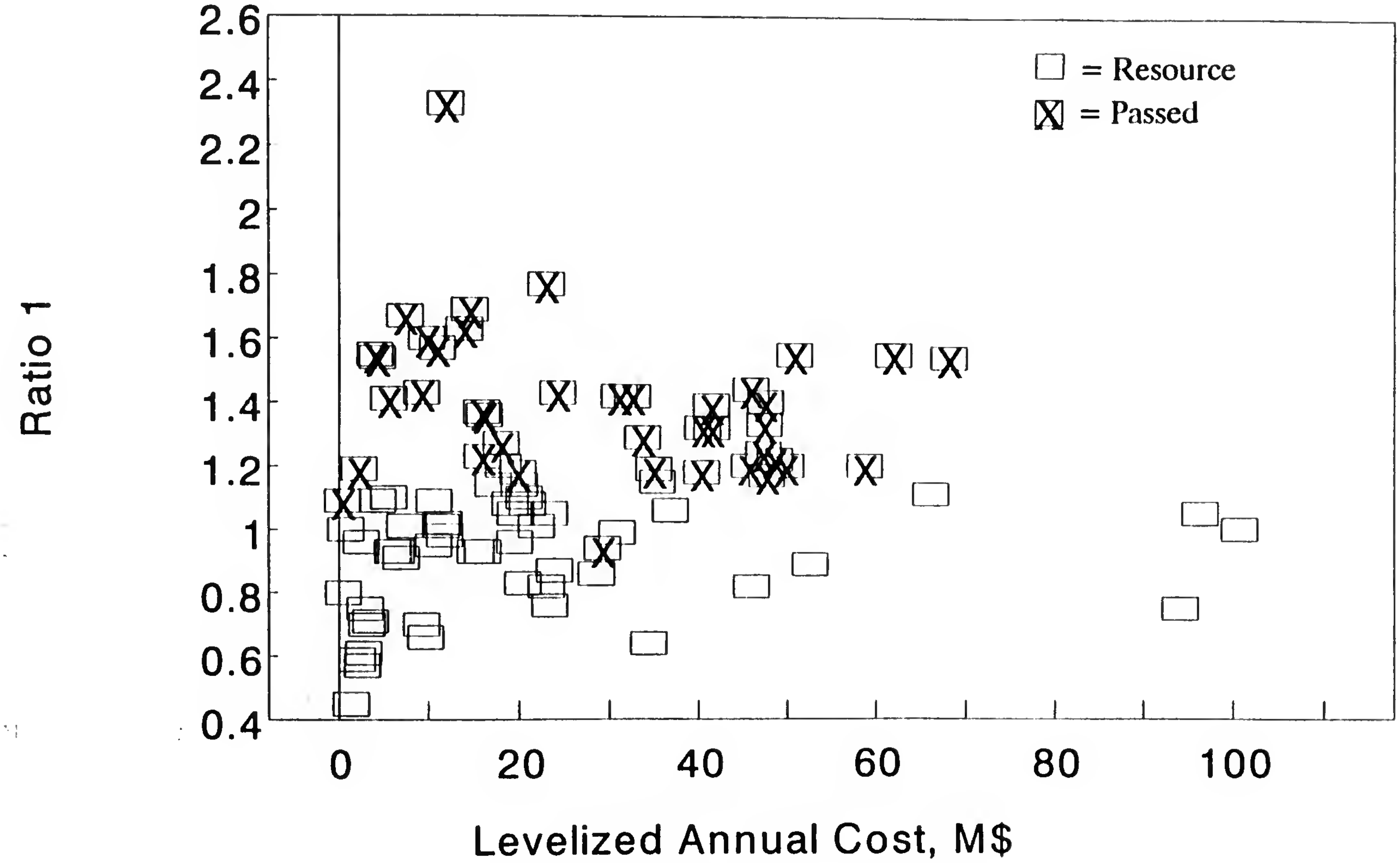
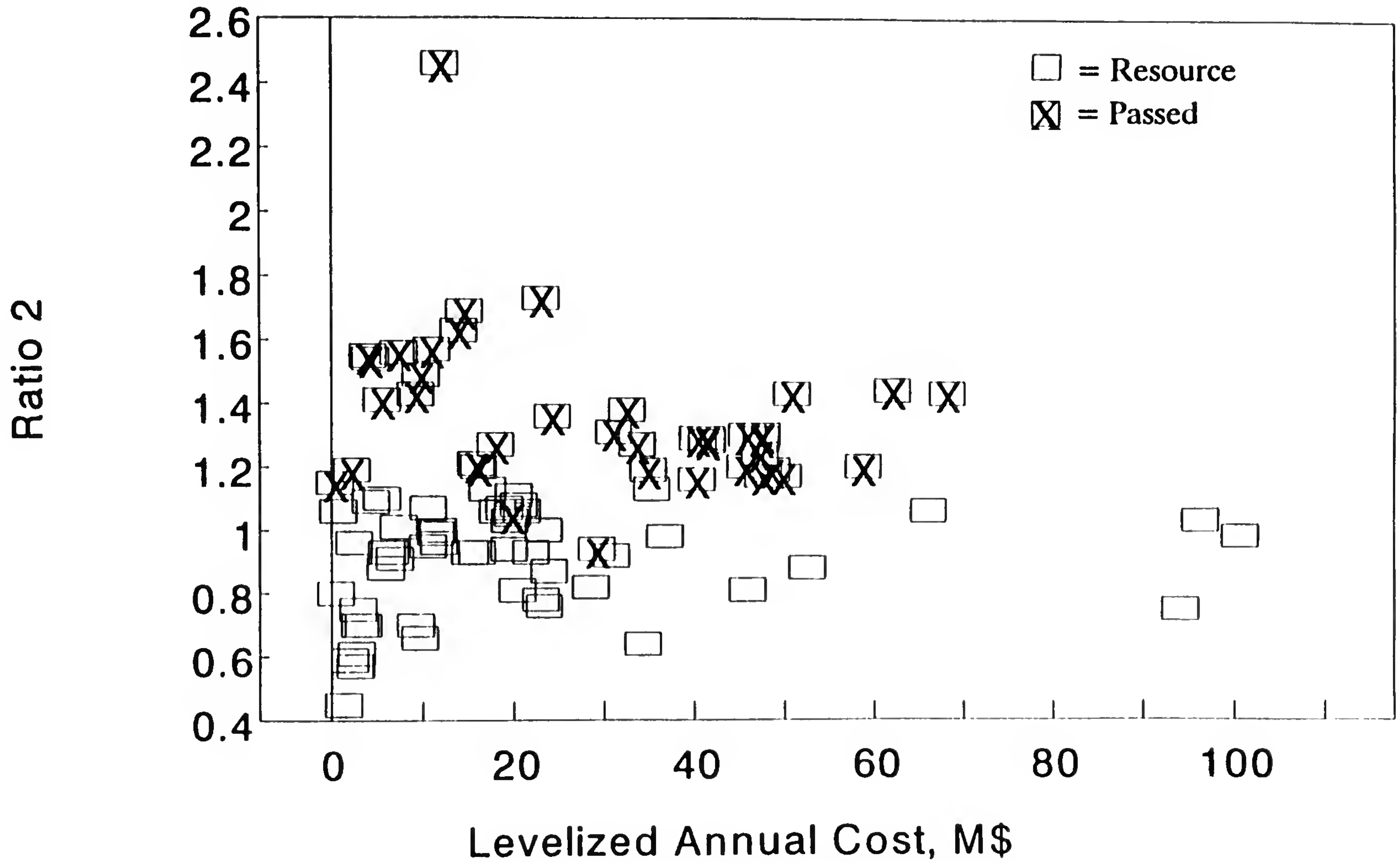
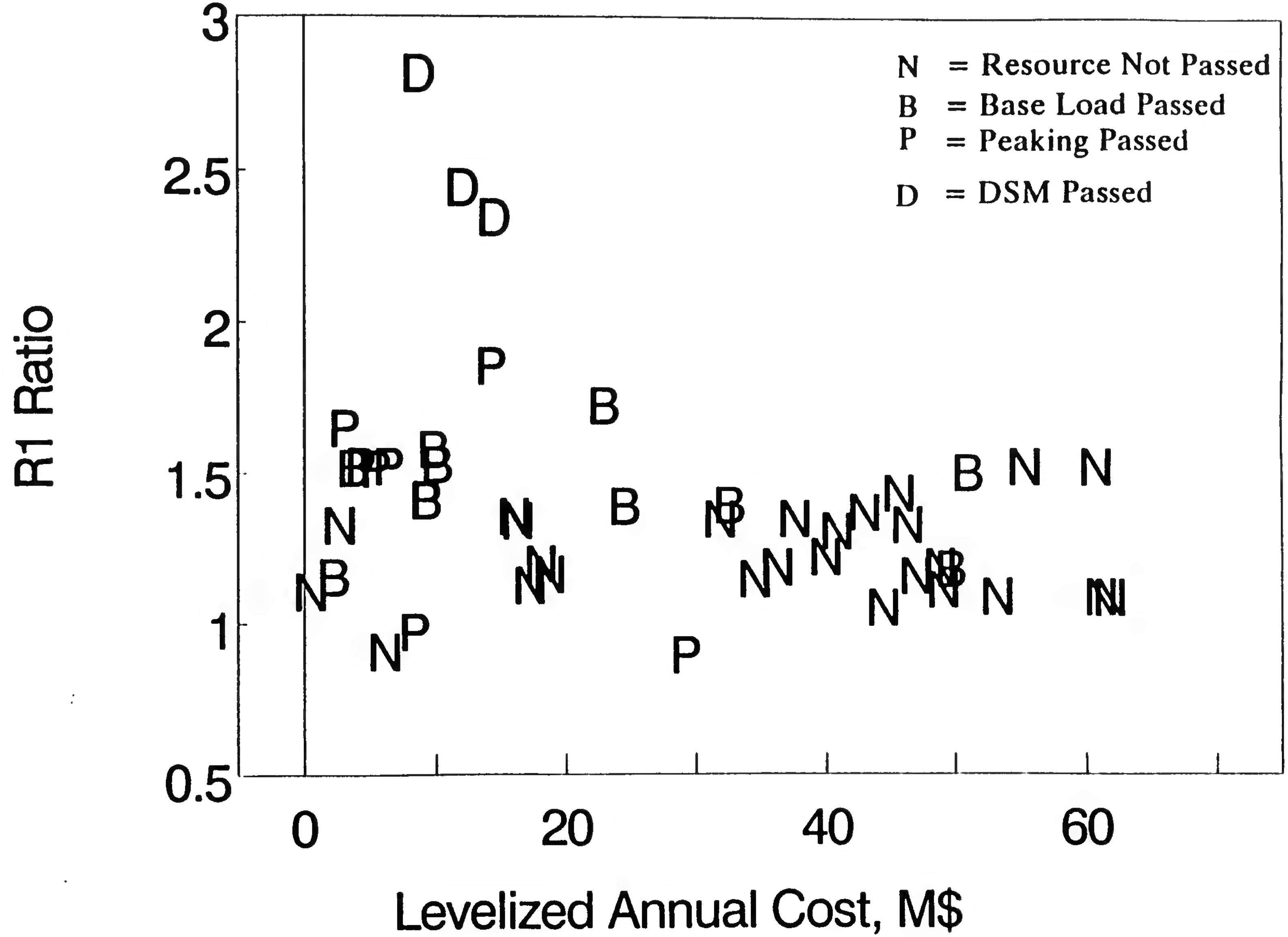


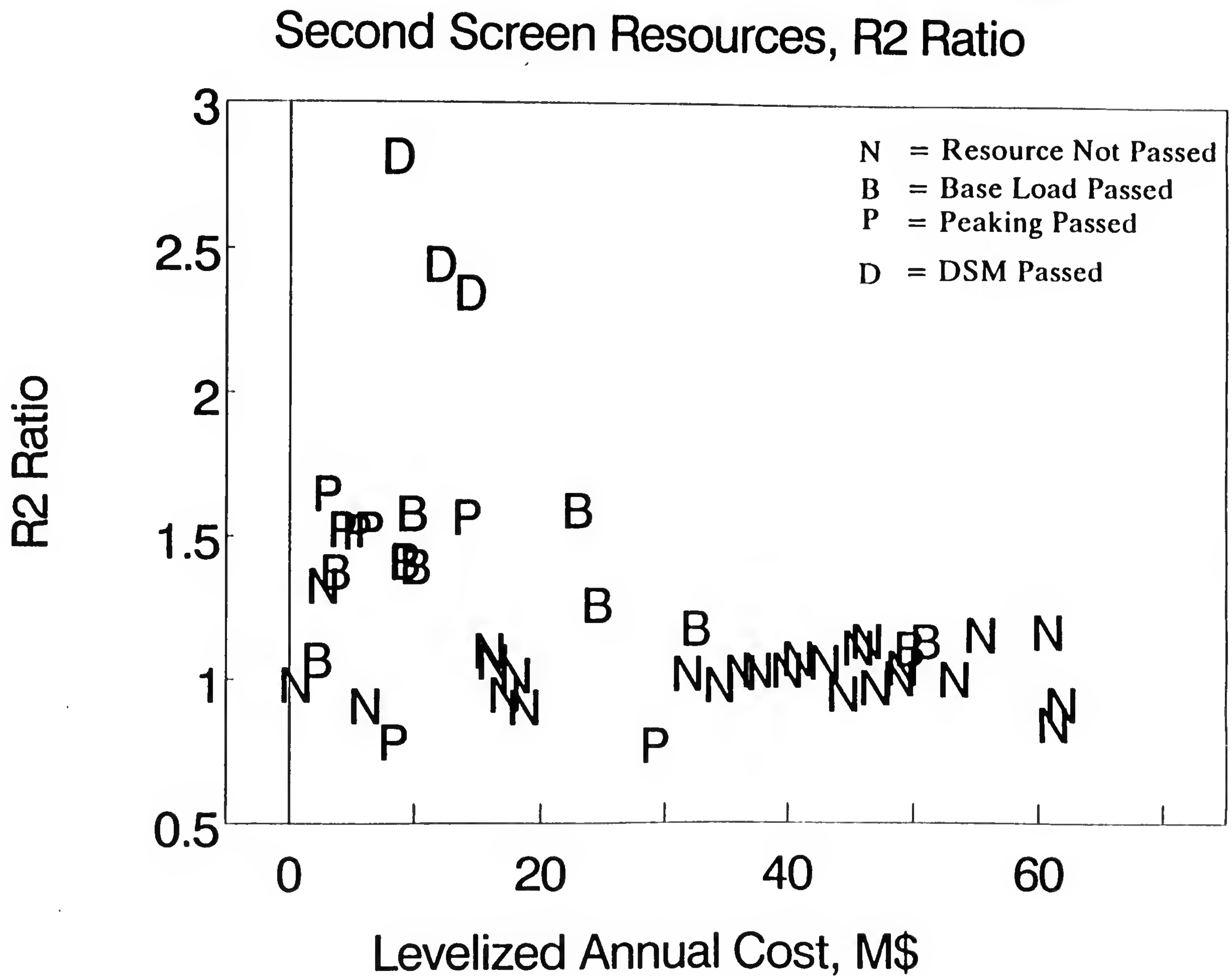
ILLUSTRATION 20

First Screen Resources, Ratio 2



Second Screen Resources, R1 Ratio




Second Screen Resources, R2 Ratio
R2 Ratio
3
2.5
2
1.5
1
0.5
0
20
40
60
Levelized Annual Cost, M$
N = Resource Not Passed
B = Base Load Passed
P = Peaking Passed
D = DSM Passed

Second Screen Resources, R3 Ratio

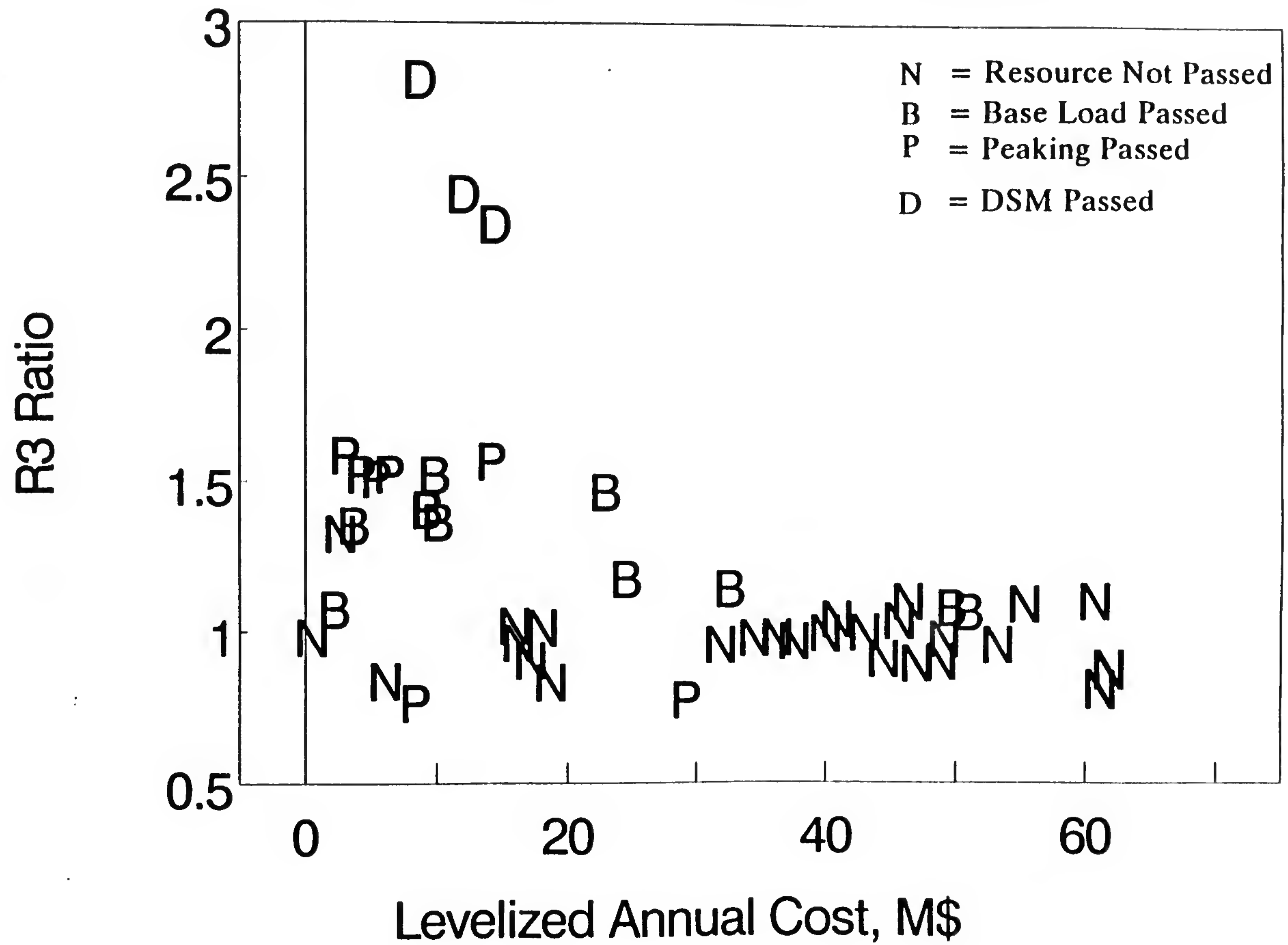
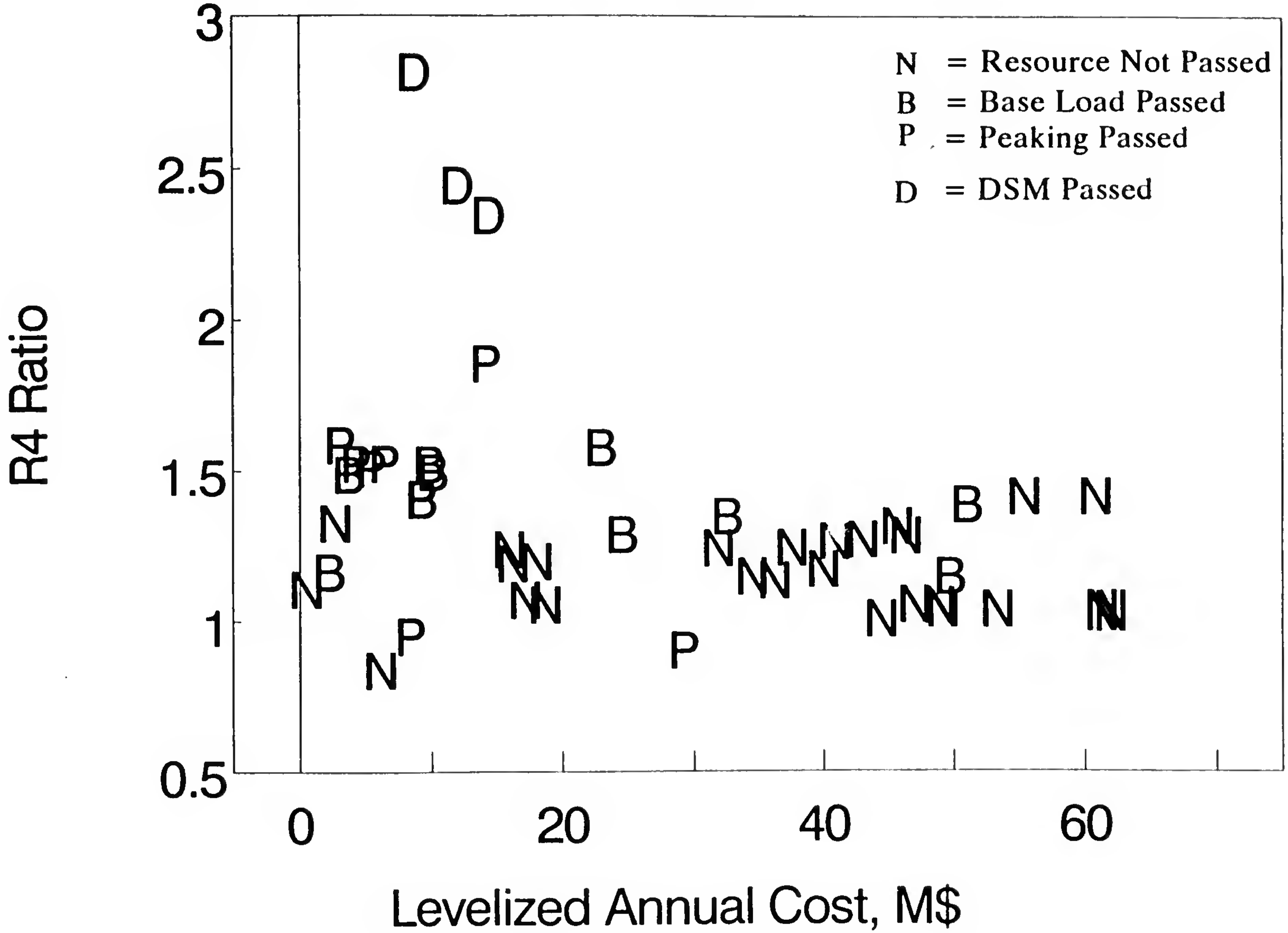


ILLUSTRATION 21

Second Screen Resources, R4 Ratio



Second Screen Resources

				TECHNOLOGY	MW	B/C	R1 Ratio	K$ DEE	R2 Ratio	MPC EEAF	R3 Ratio	R4 Ratio	IN-STATE DIRECT Jobs	PASS SECOND CUT
S	1	COAL GAS	1	CC	80	1.74	1.74	1864	1.61	1.082	1.46	1.60	No	Yes
S	2	WASTE COAL	1	CFBC	82	1.36	1.36	8800	1.04	1.063	0.86	1.26	Yes	No
	3		2	CFBC+CT	156	1.38	1.39	12162	1.08	1.077	1.02	1.26	Yes	No
B	4		3	CFBC+CT	125	1.37	1.37	11172	1.05	1.083	0.98	1.26	Yes	No
A	5		4	CFBC	40	1.37	1.37	3815	1.12	1.085	1.04	1.26	Yes	No
S	6		5	CFBC	40	1.35	1.36	4164	1.08	1.125	0.96	1.21	Yes	No
E	7		6	CFBC	40	1.17	1.18	5236	0.82	1.104	0.85	1.07	Yes	No
	8	COAL+NG	1	PC+CT	184	1.54	1.54	17001	1.18	1.075	1.11	1.43	Yes	No
L	9		2	PC+CT	227	1.54	1.54	18011	1.18	1.075	1.12	1.43	Yes	No
O	10	COAL	1	PC	181	1.52	1.52	16164	1.15	1.082	1.09	1.40	Yes	Yes
A	11	COGEN: NG	1	CT	38	1.55	1.55	964	1.41	1.023	1.36	1.51	No	Yes
D	12		2	CC	115	1.24	1.24	7147	1.05	1.042	1.02	1.18	Yes	No
	13		3	CC	121	1.20	1.21	6782	1.02	1.130	0.92	1.07	No	No
	14		4	CC	42	1.14	1.15	3185	0.97	1.054	0.92	1.09	Yes	No
	15		5	CC	113	1.17	1.18	6769	0.99	1.097	0.92	1.07	No	No
	16		6	CC	140	1.11	1.11	4577	1.02	1.047	0.98	1.06	No	No
	17		7	CC	128	1.20	1.20	3174	1.13	1.027	1.10	1.17	Yes	Yes
	18		8	CC	114	1.13	1.13	3348	1.06	1.069	1.00	1.06	No	No
	19		9	CC	111	1.07	1.07	4685	0.97	1.044	0.93	1.03	Yes	No
	20	COGEN: STEAM	1	PRESR REDCE	15	1.53	1.53	362	1.39	1.016	1.37	1.51	No	Yes
	21	COGEN: COKE	1	CFBC	68	1.41	1.41	2463	1.26	1.078	1.19	1.31	Yes	Yes
	22	COGEN: COAL	1	PC	125	1.45	1.45	12848	1.13	1.060	1.06	1.33	Yes	No
	23	NATURAL GAS	1	CC	92	1.40	1.41	5633	1.20	1.034	1.16	1.37	Yes	Yes
	24		2	CC+CT	158	1.34	1.35	7783	1.15	1.034	1.12	1.30	Yes	No
	25		3	CC+CT	125	1.32	1.33	8803	1.09	1.034	1.06	1.28	Yes	No
	26		4	CC	84	1.21	1.21	5687	1.04	1.046	1.00	1.15	No	No
	27		5	CC	156	1.08	1.10	11301	0.93	1.058	0.88	1.04	No	No
	28		6	CC	156	1.08	1.10	11301	0.93	1.043	0.80	1.08	No	No
	29		7	CC	156	1.11	1.11	17124	0.88	1.058	0.83	1.05	No	No
	30		8	CC	156	1.11	1.11	17124	0.86	1.043	0.84	1.06	No	No
	31	HYDRO	1	R-O-R	5	1.17	1.17	174	1.08	0.994	1.08	1.18	Yes	Yes
	32		2	BRD&H2O	60	1.60	1.60	0	1.60	1.038	1.54	1.54	Yes	Yes
	33		3	R-O-R	14	1.43	1.43	0	1.43	1.004	1.42	1.42	Yes	Yes
	34	SURPLUS	1	PC	114	1.17	1.17	5736	1.00	1.000	1.00	1.17	No	No
S	1	WINTER DELIV	1	SURPLS PC	68	1.87	1.87	2564	1.59	1.000	1.59	1.87	No	Yes
S	2		2	SURPLS PC	114	1.22	1.22	3161	1.03	1.000	1.03	1.22	No	No
	3	EXCHANGE	1	EX/IPC1	50	1.54	1.54	0	1.54	1.000	1.54	1.54	No	Yes
P	4		2	EX/IPC2	76	1.54	1.54	0	1.54	1.000	1.54	1.54	No	Yes
E	5		3	EX/APS	50	1.34	1.34	0	1.34	1.000	1.34	1.34	No	No
A	6	NG	1	BIRD	60	1.67	1.67	0	1.67	1.036	1.60	1.60	Yes	Yes
K	7		2	CT* 64A	33	0.86	0.89	1860	0.80	1.028	0.78	0.97	Yes	Yes
I	8		3	CT	42	0.83	0.83	0	0.83	1.081	0.86	0.86	Yes	No
N	9	HYDRO	1	RYAN	43	1.53	1.53	0	1.53	1.004	1.53	1.53	Yes	Yes
G	10		2	T.FALL	41	1.43	1.43	0	1.43	1.004	1.43	1.43	Yes	Yes
	11		3	PUMP.HYDRO*	100	0.81	0.81	4603	0.79	0.993	0.79	0.82	Yes	Yes
D	1	DEMAND-SIDE	1	MPC DSM**	116	2.33	2.48	0	2.46	1.000	2.48	2.46	No	Yes
S	2		2	MPC DSM**	89	2.66	2.83	0	2.83	1.000	2.83	2.63	No	Yes
M	3		3	MPC DSM**	140	2.24	2.37	0	2.37	1.000	2.37	2.37	No	Yes
	4		4	DSM	2	1.07	1.13	44	1.00	1.000	1.00	1.13	No	No

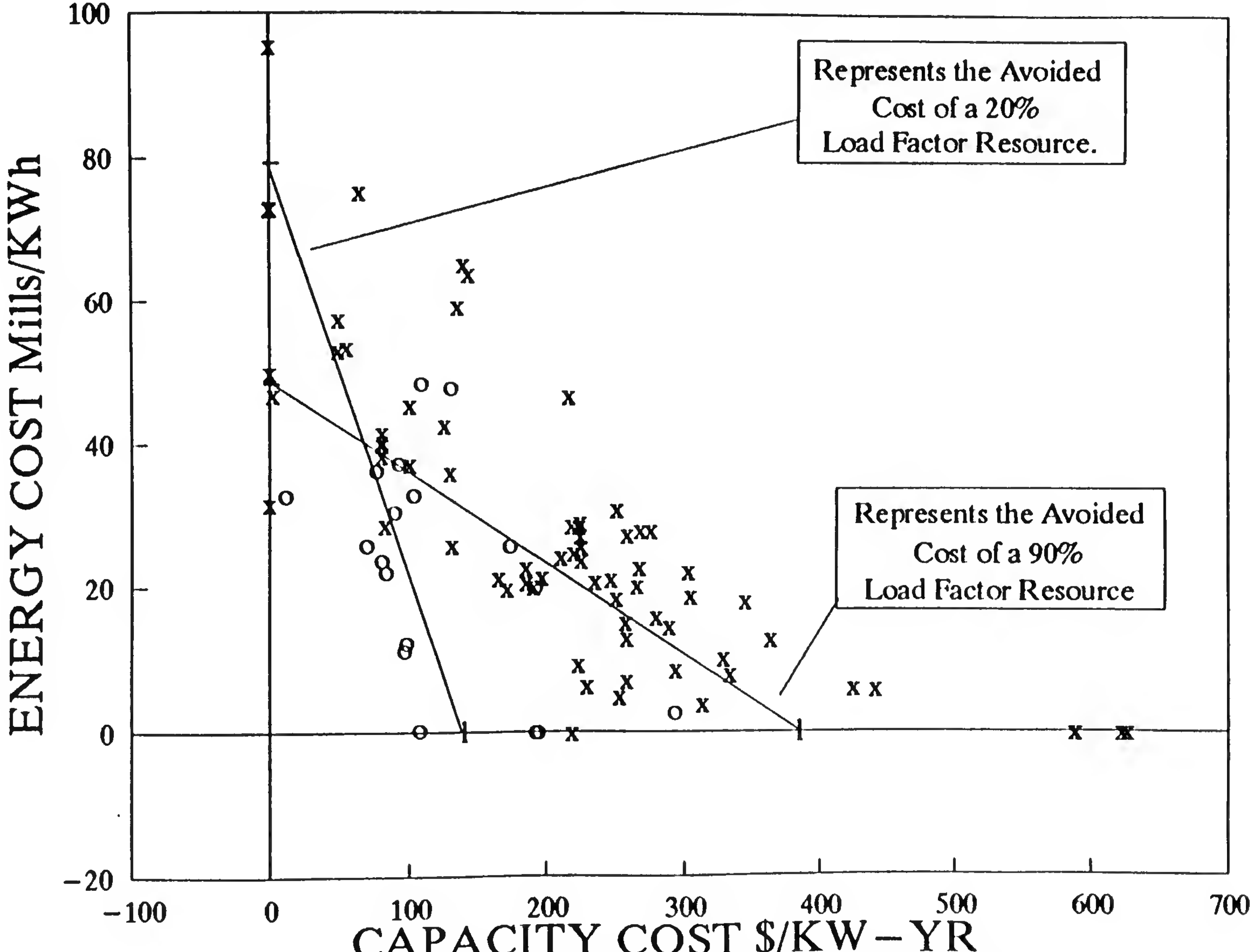
* B/C & 'R' VALUE VARIES DEPENDING ON THE PUMPING COSTS.
** MPC DSM ALTERNATIVES ARE MUTUALLY EXCLUSIVE.

ILLUSTRATION 22

ILLUSTRATION 23

STATIC ANALYSIS

ENERGY COST V.S. CAPACITY COST



o = Passed, x = Not Passed, Demand-Side Resources Not Shown

ILLUSTRATION 24

10-Apr-92

MONTANA POWER COMPANY

EN3PCG.WK3

RESOURCE ENVIRONMENTAL ASSESSMENT MATRIX
FOR
PULVERIZED COAL-GENERIC

SCORE = 2.14

ENVIRONMENTAL CONCERN		CONTRIBUTING FACTOR		IMPACT: LEAST				MOST		
Weight	Issue	Weight	Factor	0	1	2	3	4	Factor Impact	Factor Score
15%	Land Use	6%	Amount (acres/MW capacity)	0-0.36	0.37-0.72	0.73-1.08	1.09-1.44	1.45-1.80	3	0.18
		4%	Zoning/Land Use Planning	Heavy industrial or unzoned/not subject to land use planning	Light industrial	Commercial or agricultural	School or residential	Open space or recreational	2	0.08
		5%	Present Usage	Onsite/proximate heavy industry	Light industry or grazing agriculture	Retail/commercial or tilled agriculture	Residential or developed areas	Pristine or area with high scenic value	2	0.10
11%	Visual Aesthetics	5%	Impact to Passers-by	Not visible from federal or state highways or local roads	Visible from local roads only	Visible from federal or state highway, urban surroundings	Visible from federal or state highway, rural surroundings	Visible from federal or state highway, pristine surroundings	3	0.15
		6%	Impact to Residents	Not visible from urban or rural dwellings or businesses	Visible from businesses, industrial/commercial surroundings	Visible from urban dwellings, developed surroundings	Visible from urban dwellings, undeveloped surroundings	Visible from rural dwellings, undeveloped surroundings	2	0.12
5%	Global Climate	5%	Carbon Dioxide (lb/MWh)	0-830	831-1660	1661-2490	2491-3120	3121-4150	2	0.10
7%	Acid Rain	4%	Sulfur Dioxide (lb/MWh)	0-2.28 or allowances acquired	2.29-4.56	4.57-6.84	6.85-9.12	9.13-11.40	2	0.08
		3%	Nitrogen Oxides (lb/MWh)	0-1.52	1.53-3.04	3.05-4.56	4.57-6.08	6.09-7.60	3	0.09
5%	Smog Generation	2%	VOCs (lb/MWh)	0-0.046	0.047-0.092	0.093-0.138	0.139-0.184	0.185-0.230	0	0.00
		3%	Nitrogen Oxides (lb/MWh)	0-1.52	1.53-3.04	3.05-4.56	4.57-6.08	6.09-7.60	3	0.09
10%	Other Emissions to Air	3%	Air Toxics (any combination of "Hazardous Air Pollutants") (lb/MWh)	0-0.028	0.029-0.056	0.057-0.084	0.085-0.112	0.113-0.140	2	0.06
		4%	Particulates (lb/MWh)	0-0.066	0.067-0.132	0.133-0.198	0.199-0.264	0.265-0.330	4	0.16
		3%	Carbon Monoxide (lb/MWh)	0-0.114	0.115-0.228	0.229-0.342	0.343-0.456	0.457-0.570	3	0.09
13%	Solid and Liquid Wastes	4%	Amount of Solid Waste Generated (lb/MWh)	0-120	121-240	241-360	361-480	481-600	1	0.04
		4%	Amount of Liquid Waste Generated (lb/MWh)	0-36	37-72	73-108	109-144	145-180	4	0.16
		5%	Type of Disposal	No waste	Recycling/recovery	Incineration with energy recovery	Incineration without energy recovery	Landfill disposal	4	0.20

10-Apr-92

MONTANA POWER COMPANY

EN3PCO.WK3

RESOURCE ENVIRONMENTAL ASSESSMENT MATRIX
FOR
PULVERIZED COAL-GENERIC

SCORE = 2.14

ENVIRONMENTAL CONCERN		CONTRIBUTING FACTOR		LEAST	----------IMPACT----------			MOST	Factor	Factor
Weight	Issue	Weight	Factor	0	1	2	3	4	Impact	Score
14%	Surface/Ground Water Use and Quality	3%	Amount (gal/MWh)	0-120	121-240	241-360	361-480	481-600	3	0.09
		2%	Attributes of Input Water	No water used				Pristine waters with high scenic, wildlife, fisheries or recreational attributes	2	0.04
		3%	Source	No water used	Contaminated or recycled water	Water previously appropriated for industrial use	Water with high potential for domestic consumption or recreational use	Sole-source aquifer	2	0.06
		3%	Net Thermal Effect on Receiving Water	No water discharged or no temperature change				Some increase to receiving water	0	0.00
		3%	Net Chemical Effect on Receiving Water	No water discharged or no chemical change		Moderate chemical change to receiving water		Major chemical change to receiving water	0	0.00
15%	Outdoor Resources	4%	Wildlife	No reduction in or disruption of wildlife		Minor reduction in or disruption of wildlife		Major reduction in or disruption of wildlife	2	0.08
		4%	Fisheries	No reduction in or disruption of fisheries		Minor reduction in or disruption of fisheries		Major reduction in or disruption of fisheries	0	0.00
		3%	Habitat	No reduction in or disruption of habitat		Minor reduction in or disruption of habitat		Major reduction in or disruption of habitat	2	0.06
		4%	Recreation	No change in nearby recreational opportunities		Minor change in nearby recreational opportunities		Major change in nearby recreational opportunities	0	0.00
5%	Other Public Concerns	2%	Audible Noise (dB (A) at property line) (example)	15 dB Broadcasting studio	25 dB Bedroom at night	35 dB Library	45 dB Living room	55 dB Typical business office	4	0.08
		2%	Electromagnetic Fields (milligauss at property line)	0-20	21-40	41-60	61-80	81-100	1	0.02
		1%	Radio/TV Interference (signal-to-noise level (dB))	46 or >	36-45	26-35	16-25	<=15	1	0.01

Notes:

ILLUSTRATION 25

DYNAMIC ANALYSIS, STEP 1 RESULTS

					STATIC SCREEN STATISTICS						
		FUEL	TECHNOLOGY	MW	B/C	R1 Ratio	R2 Ratio	R3 Ratio	R4 Ratio	PASS	STEP 1 DYNAMIC ANALYSIS***
B	1	COAL GAS	CC	80	1.74	1.74	1.61	1.48	1.60	Yes	ALTERNATE LIST
A	2	COAL	PC	161	1.52	1.52	1.15	1.09	1.40	Yes	ALTERNATE LIST
S	3	COGEN: NG	CT	38	1.55	1.55	1.41	1.38	1.51	Yes	PASSED
E	4	COGEN: NG	CC	129	1.20	1.20	1.13	1.10	1.17	Yes	ALTERNATE LIST
	5	COGEN: STEAM	PRESR REDCE	15	1.53	1.53	1.39	1.37	1.51	Yes	MOVED
L	6	COGEN: COKE	CFBC	68	1.41	1.41	1.28	1.19	1.31	Yes	PASSED
O	7	NATURAL GAS	CC	92	1.40	1.41	1.20	1.16	1.37	Yes	PASSED
A	8	HYDRO	RUN-OF-RIVER (ROR)	5	1.17	1.17	1.09	1.09	1.18	Yes	MOVED
D	9	HYDRO & NG	BIRD & H2O	60	1.60	1.60	1.60	1.54	1.54	Yes	PASSED
	10	HYDRO	T.FALLS ROR	14	1.43	1.43	1.43	1.42	1.42	Yes	ALTERNATE LIST
P	11	WINTER DELIV	SURPLS PC	98	1.87	1.87	1.59	1.59	1.87	Yes	PASSED
E	12	EXCHANGE	EXCHANGE/IPC1	50	1.54	1.54	1.54	1.54	1.54	Yes	PASSED
A	13	EXCHANGE	EXCHANGE/IPC2	76	1.54	1.54	1.54	1.54	1.54	Yes	MOVED
K	14	NG	BIRD	60	1.67	1.67	1.67	1.60	1.60	Yes	PASSED
I	15	NG	CT	33	0.99	0.99	0.80	0.78	0.97	Yes	PASSED
N	16	HYDRO	RYAN	43	1.53	1.53	1.53	1.53	1.53	Yes	PASSED
G	17	HYDRO	T.FALLS	41	1.43	1.43	1.43	1.43	1.43	Yes	PASSED
	18	HYDRO	PUMP.HYDRO*	100	0.91	0.91	0.79	0.79	0.92	Yes	PASSED
D	19	DEMAND-SIDE	MPC DSM(SASA)**	116	2.33	2.46	2.46	2.46	2.46	Yes	PASSED
S	20	DEMAND-SIDE	MPC DSM(SSSS)**	89	2.68	2.83	2.83	2.83	2.83	Yes	MOVED
M	21	DEMAND-SIDE	MPC DSM(AAAA)**	140	2.24	2.37	2.37	2.37	2.37	Yes	PASSED

* B/C & 'R' VALUE VARIES DEPENDING ON THE PUMPING COSTS.

** MPC DSM ALTERNATIVES ARE MUTUALLY EXCLUSIVE, MW SHOWN REPRESENTS AMOUNTS ACQUIRED BY 2001.

*** MOVED MEANS THE RESOURCE WAS MOVED TO THE STEP 2 FOR ANALYSIS.

ILLUSTRATION 26

DYNAMIC ANALYSIS, STEP 2 RESULTS

					STATIC SCREEN STATISTICS							
		FUEL	TECHNOLOGY	MW	B/C	R1 Ratio	R2 Ratio	R3 Ratio	R4 Ratio	PASS	STEP 1 DYNAMIC ANALYSIS***	STEP 2 DYNAMIC ANALYSIS
B	1	COAL GAS	CC	80	1.74	1.74	1.61	1.48	1.60	Yes	ALTERNATE LIST	ALTERNATE LIST
A	2	COAL	PC	161	1.52	1.52	1.15	1.09	1.40	Yes	ALTERNATE LIST	ALTERNATE LIST
S	3	COGEN: NG	CT	38	1.55	1.55	1.41	1.38	1.51	Yes	PASSED	PASSED
E	4	COGEN: NG	CC	129	1.20	1.20	1.13	1.10	1.17	Yes	ALTERNATE LIST	ALTERNATE LIST
	5	COGEN: STEAM	PRESR REDCE	15	1.53	1.53	1.39	1.37	1.51	Yes	MOVED	PASSED
L	6	COGEN: COKE	CFBC	68	1.41	1.41	1.28	1.19	1.31	Yes	PASSED	PASSED
O	7	NATURAL GAS	CC	92	1.40	1.41	1.20	1.16	1.37	Yes	PASSED	PASSED
A	8	HYDRO	RUN-OF-RIVER (ROR)	5	1.17	1.17	1.09	1.09	1.18	Yes	MOVED	PASSED
D	9	HYDRO & NG	BIRD & H2O	60	1.60	1.60	1.60	1.54	1.54	Yes	PASSED	PASSED
	10	HYDRO	T.FALLS ROR	14	1.43	1.43	1.43	1.42	1.42	Yes	ALTERNATE LIST	ALTERNATE LIST
P	11	WINTER DELIV	SURPLS PC	98	1.87	1.87	1.59	1.59	1.87	Yes	PASSED	PASSED
E	12	EXCHANGE	EXCHANGE/IPC1	50	1.54	1.54	1.54	1.54	1.54	Yes	PASSED	PASSED
A	13	EXCHANGE	EXCHANGE/IPC2	76	1.54	1.54	1.54	1.54	1.54	Yes	MOVED	PASSED
K	14	NG	BIRD	60	1.67	1.67	1.67	1.60	1.60	Yes	PASSED	PASSED
I	15	NG	CT	33	0.99	0.99	0.80	0.78	0.97	Yes	PASSED	ALTERNATE LIST
N	16	HYDRO	RYAN	43	1.53	1.53	1.53	1.53	1.53	Yes	PASSED	PASSED
G	17	HYDRO	T.FALLS	41	1.43	1.43	1.43	1.43	1.43	Yes	PASSED	PASSED
	18	HYDRO	PUMP.HYDRO*	100	0.91	0.91	0.79	0.79	0.92	Yes	PASSED	ALTERNATE LIST
D	19	DEMAND-SIDE	MPC DSM(SASA)**	116	2.33	2.46	2.46	2.46	2.46	Yes	PASSED	PASSED
S	20	DEMAND-SIDE	MPC DSM(SSSS)**	89	2.68	2.83	2.83	2.83	2.83	Yes	MOVED	ALTERNATE LIST
M	21	DEMAND-SIDE	MPC DSM(AAAA)**	140	2.24	2.37	2.37	2.37	2.37	Yes	PASSED	ALTERNATE LIST

* B/C & "R" VALUE VARIES DEPENDING ON THE PUMPING COSTS.
** MPC DSM ALTERNATIVES ARE MUTUALLY EXCLUSIVE, MW SHOWN REPRESENTS AMOUNTS ACQUIRED BY 2001.
*** MOVED MEANS THE RESOURCE WAS MOVED TO THE STEP 2 FOR ANALYSIS.

ILLUSTRATION 27

DYNAMIC ANALYSIS - STEP TWO

SELECTION CRITERIA

1. MPC SHOULD PLAN TO ACQUIRE ALL COST EFFECTIVE DEMAND-SIDE RESOURCE IN A MANNER THAT WILL BEST MEET OUR CUSTOMERS NEED FOR RESOURCE.

2. THE EXACT QUANTITIES AND PRICE OF DEMAND-SIDE RESOURCE IS NOT KNOWN AT THIS TIME. THE SELECTION CRITERIA MUST IDENTIFY RESOURCE PLANS THAT CAN BE USED TO ADDRESS THIS UNCERTAINTY.

   METHOD: FOCUS ON THE SASA DEMAND-SIDE RESOURCE AND IDENTIFY SIMILAR RESOURCE PLANS USING THE SSSS AND AAAA DEMAND-SIDE RESOURCE ALTERNATIVES.

   USE THE SSSS AND AAAA INFORMATION TO UNDERSTAND THE SUPPLY-SIDE RESOURCE FLEXABILITY REQUIRED.

   COMMIT TO ADJUSTING THE SASA SUPPLY-SIDE RESOURCES TO ACCOMODATE ALL COST EFFECTIVE DEMAND-SIDE RESOURCE.

3. IDENTIFY RESOURCE PLANS THAT MINIMIZE LONG TERM TPV TOTAL SOCIETAL COST WITH SHORT TERM CONSIDERATIONS.

4. THE RESOURCE PLANS SHOULD STRIVE TO MAINTAIN PEAK BALANCE NEAR ZERO AND ENERGY BALANCE GREATER THAN OR EQUAL TO ZERO USING CRITICAL WATER PLANNING CRITERIA.

   TO INSURE CONSISTENT ANALYSIS OF PLANS AND TO AVOID BIAS TOWARD PLANS THAT DO NOT MEET FORECAST NEED THE FOLLOWING METHOD WILL BE USED.

   METHOD: A. ANY PLAN WITH A PEAK LOAD AND RESOURCE BALANCE DEFICIENCY IN THE BID WINDOW GREATER THAN 17 MW PER YEAR IS NOT ACCEPTABLE. THE 17 MW PER YEAR IS THE 1996-2000 AVERAGE PEAK LOAD GROWTH.

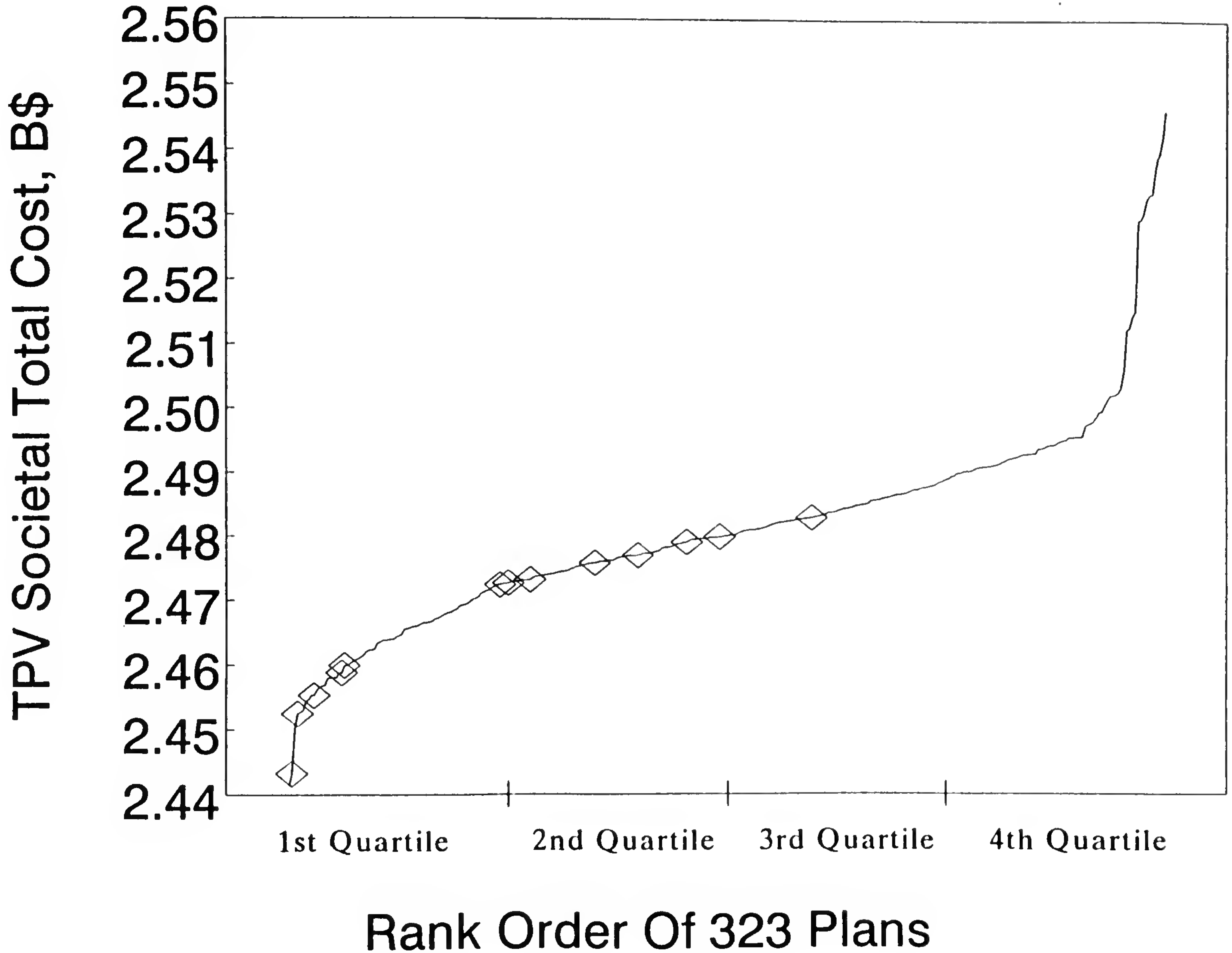
   AND

   B. TO AVOID CHRONIC DEFICIENCIES, ANY PLAN WITH THREE CONSECUTIVE YEARS OF DEFICIENCIES WITH THE THIRD YEAR'S DEFICIENCY GREATER THAN ONE HALF YEARS LOAD GROWTH (I.E. 8.5 MW) IS NOT ACCEPTABLE.

5. INSURE ALL RESOURCE ALTERNATIVES APPEAR IN AT LEAST ONE RESOURCE PLAN UNLESS THE ECONOMICS DICTATE OTHERWISE.

ILLUSTRATION 28

Dynamic Analysis Step 2



	Resource Plan Resource Statics													
	Ryan 43 MW	Bird Firm'ng 60 MW	Thom'sn Falls 41 MW	Bird Peaking 60 MW	IPCo Exch'ng 50 MW	IPCo Exch'ng 76 MW	Tiber Hydro 5 MW	Westm'nd CC 92 MW	Stone #B 15 MW	LS Pwr 68 MW	Stone #C 38 MW	Basin Antelope 98 MW	Pump Hydro 100 MW	Comb'n Turb'n 33 MW
1st Quartile	21	20	29	40	30	44	33	5	57	4	64	76	0	42
2nd Quartile	36	24	37	28	26	42	36	16	46	6	49	67	0	56
3rd Quartile	49	24	36	22	29	37	39	9	44	15	44	69	0	89
4th Quartile	52	34	34	13	26	27	42	11	40	25	28	69	13	76
Total	158	102	136	103	111	150	150	41	187	50	185	281	13	263

1st Quartile	25.9%	24.7%	35.8%	49.4%	37.0%	54.3%	40.7%	6.2%	70.4%	4.9%	79.0%	93.8%	0.0%	51.9%
2nd Quartile	44.4%	29.6%	45.7%	34.6%	32.1%	51.9%	44.4%	19.8%	56.8%	7.4%	60.5%	82.7%	0.0%	69.1%
3rd Quartile	60.5%	29.6%	44.4%	27.2%	35.8%	45.7%	48.1%	11.1%	54.3%	18.5%	54.3%	85.2%	0.0%	109.9%
4th Quartile	65.0%	42.5%	42.5%	16.3%	32.5%	33.8%	52.5%	13.8%	50.0%	31.3%	35.0%	86.3%	16.3%	95.0%
% Out of 323	48.9%	31.6%	42.1%	31.9%	34.4%	46.4%	46.4%	12.7%	57.9%	15.5%	57.3%	87.0%	4.0%	81.4%

FINAL PLANS
RESOURCE PLANS WITH SASA DSM

			Resource Timings With SASA Demand Side Resource											
	1992-2030 Lvl Inc	1992-2010 Lvl Inc		Thom'sn	Bird			IPCo Exchange		Stone Container		Basin	Tiber	Westm'nd
			Ryan	Falls	Firm'ng	Peaking	LS Pwr			#B	#C	Antelope	Hydro	CC
Plan #	Rev.Req., M$	Rev.Req., M$	43 MW	41 MW	60 MW	60 MW	68 MW	50 MW	76 MW	15 MW	38 MW	98 MW	5 MW	92 MW
2	299.5	248.6				1997		1998		1996	1996	1997	2000	
4	301.4	251.6		2000		1997		1998		1996	1996	1997		
133	301.0	256.1		1997		1997			1996					1996
7	301.6	251.0	1999			1997		1998		1996	1996	1997		
113	301.4	255.4	1997			1997			1996					1996
56	301.8	253.4	1997	1997				1998			1996	1996		
142	303.6	258.7	1997	2000		1997			1996					1996
66	299.2	252.7							1996			1997		1996
124	301.5	255.3				1997		1998				1997		1996
92	300.6	254.3		1997			1997	1998		1996		1996		
101	300.2	254.7		1997			1996		1996			1997		
28	300.9	253.3		1997	1997			1998		1996		1996		
2 X	300.1	249.7			1997				1996		1996	1996		

1992 Business Plan Resource, 1992-2001						
	Bird	Thom'sn	IPCo		Cmbst	Demand
Ryan	Firm'ng	Falls	Exch'ge	P.H.	Turbine	Side
43 MW	60 MW	50 MW	50 MW	50 MW	42 MW	Resource
1998	1997	1997	1998	1997	1997 2002	"SASA"

NOTE:

> Revenue Requirements (Rev Req) is the sum of the O&M costs for existing units plus future units revenue requirement plus new transmission and distribution revenue requirements.

> To acquire the demand-side resource additional contribution by the customer of approximately $6.0 M per year (levelized) is required above the levelized revenue requirement amounts shown.

ILLUSTRATION 30

Pump Hydro Analysis
Difference From Plan 2

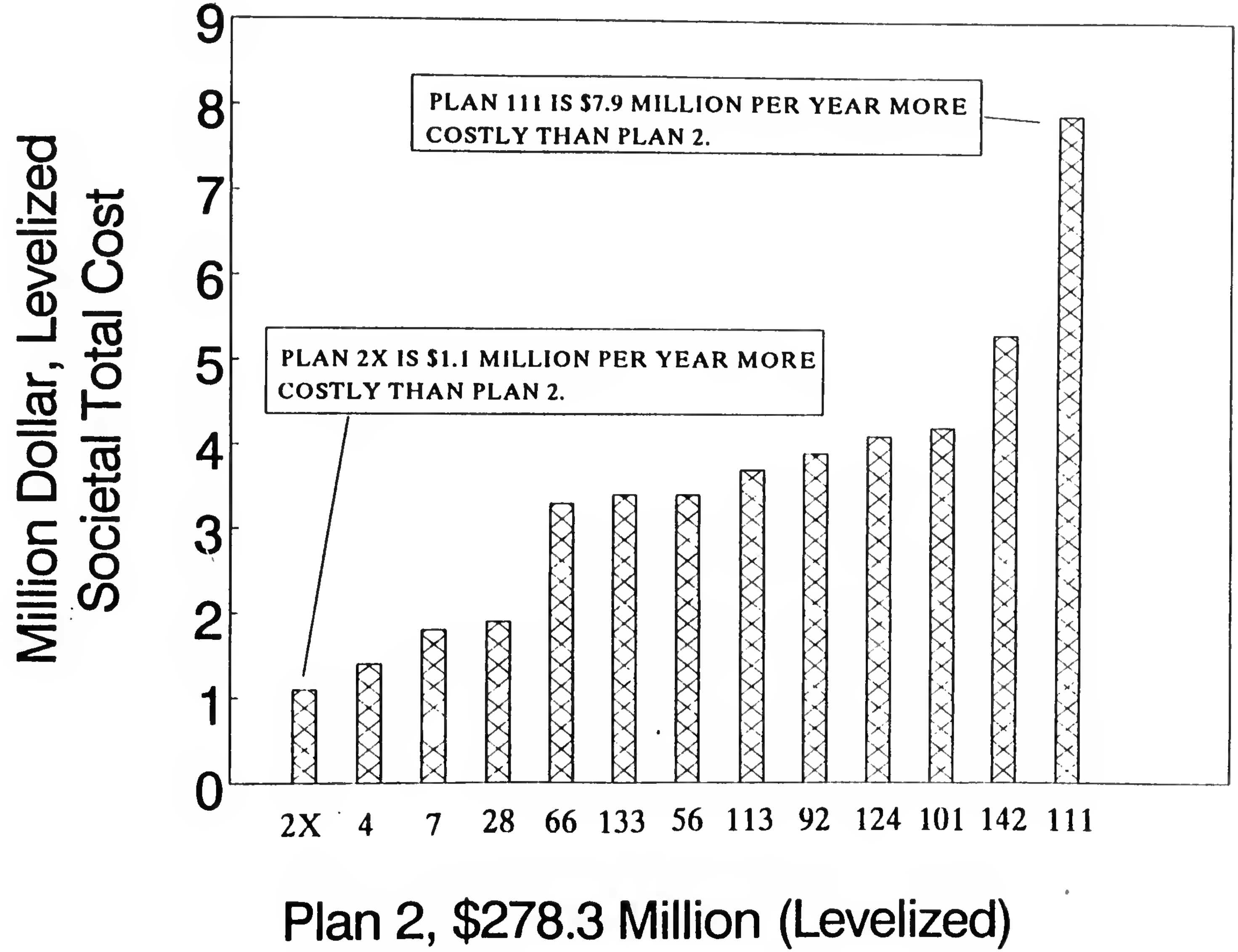
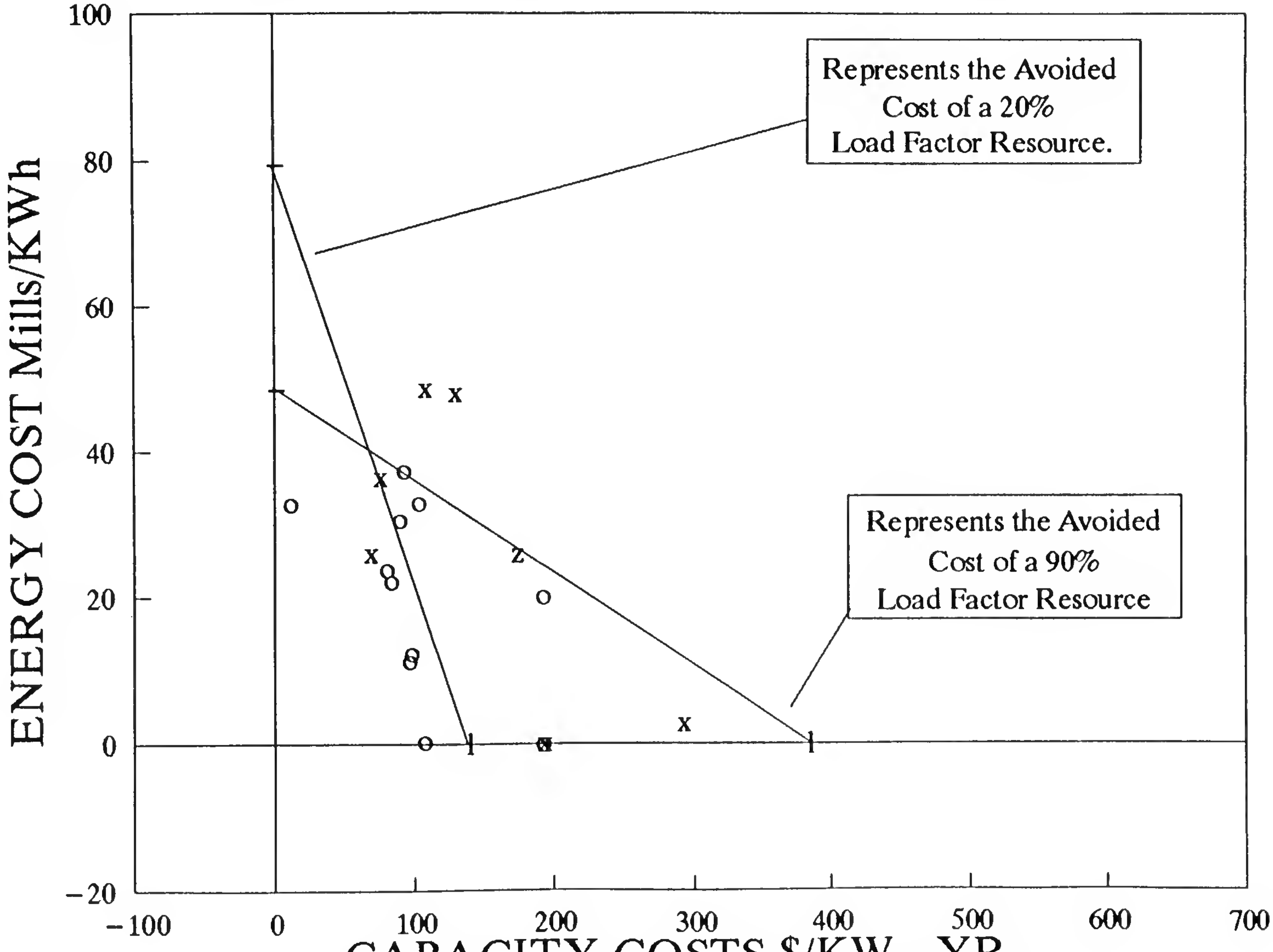


ILLUSTRATION 31

DYNAMIC ANALYSIS

ENERGY COST V.S. CAPACITY COST



o = Passed x = Not Passed z = Brought Back In; Demand−Side Resources Not Shown

ILLUSTRATION 32

Load Forecast Comparison

	R92 Forecast		R93 Forecast		R93-R92 Forecast	
	Annual Avg MW	Jan. MW	Annual Avg MW	Jan. MW	Annual Avg MW	Jan. MW
1993	974	1485	982	1439	8	-46
1994	1001	1521	1007	1475	6	-46
1995	1019	1550	1033	1511	14	-39
1996	1037	1575	1058	1546	21	-29
1997	1052	1598	1078	1573	26	-25
1998	1062	1614	1096	1599	34	-15
1999	1067	1626	1111	1621	44	-5
2000	1077	1643	1123	1640	46	-3
2001	1091	1663	1134	1656	43	-7
2002	1106	1687	1144	1671	38	-16
2003	1121	1713	1154	1685	33	-28
2004	1135	1735	1164	1700	29	-35
2005	1155	1765	1175	1716	20	-49
2006	1177	1798	1189	1740	12	-58

ILLUSTRATION 33

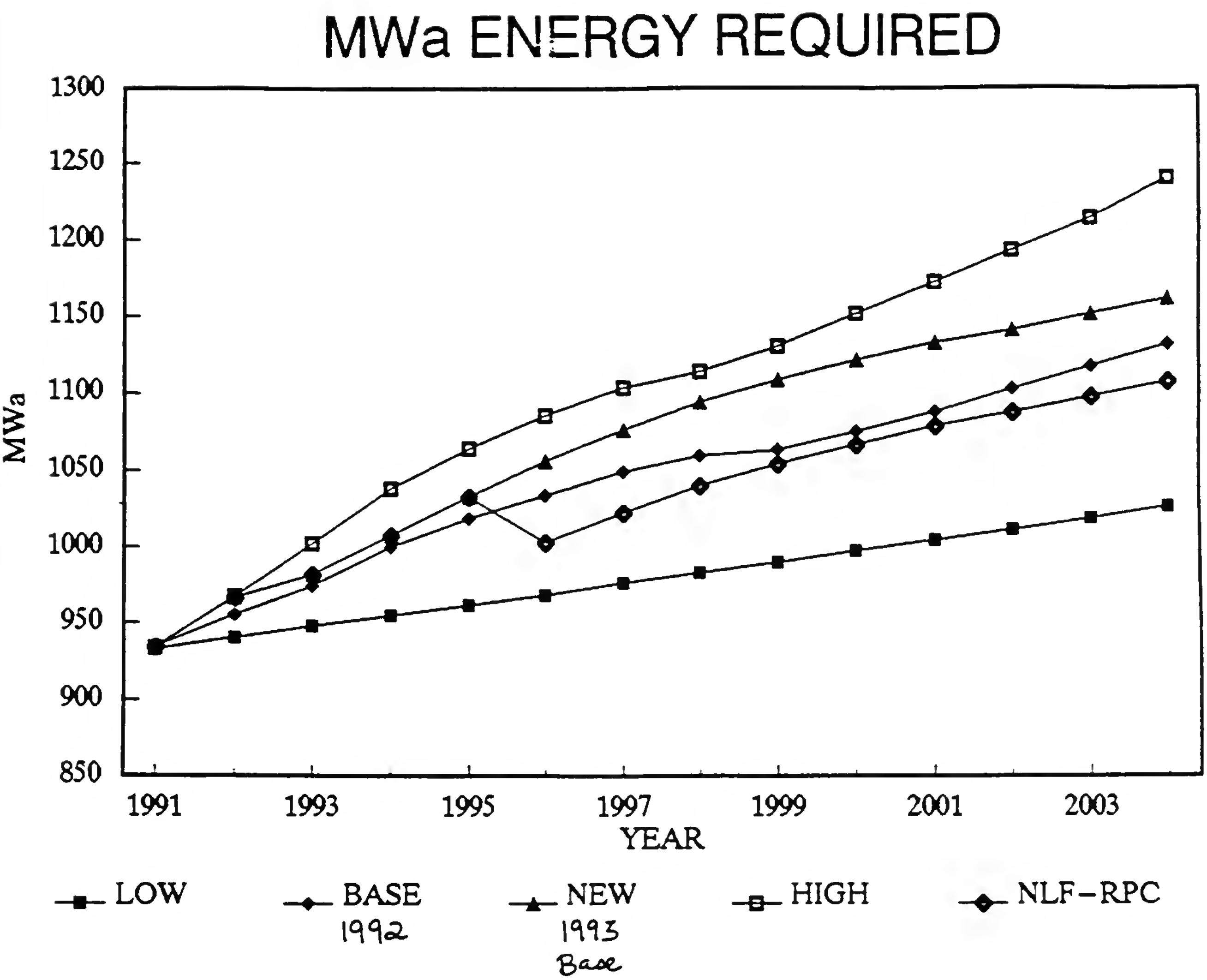


ILLUSTRATION 34

Off-System Sales Price

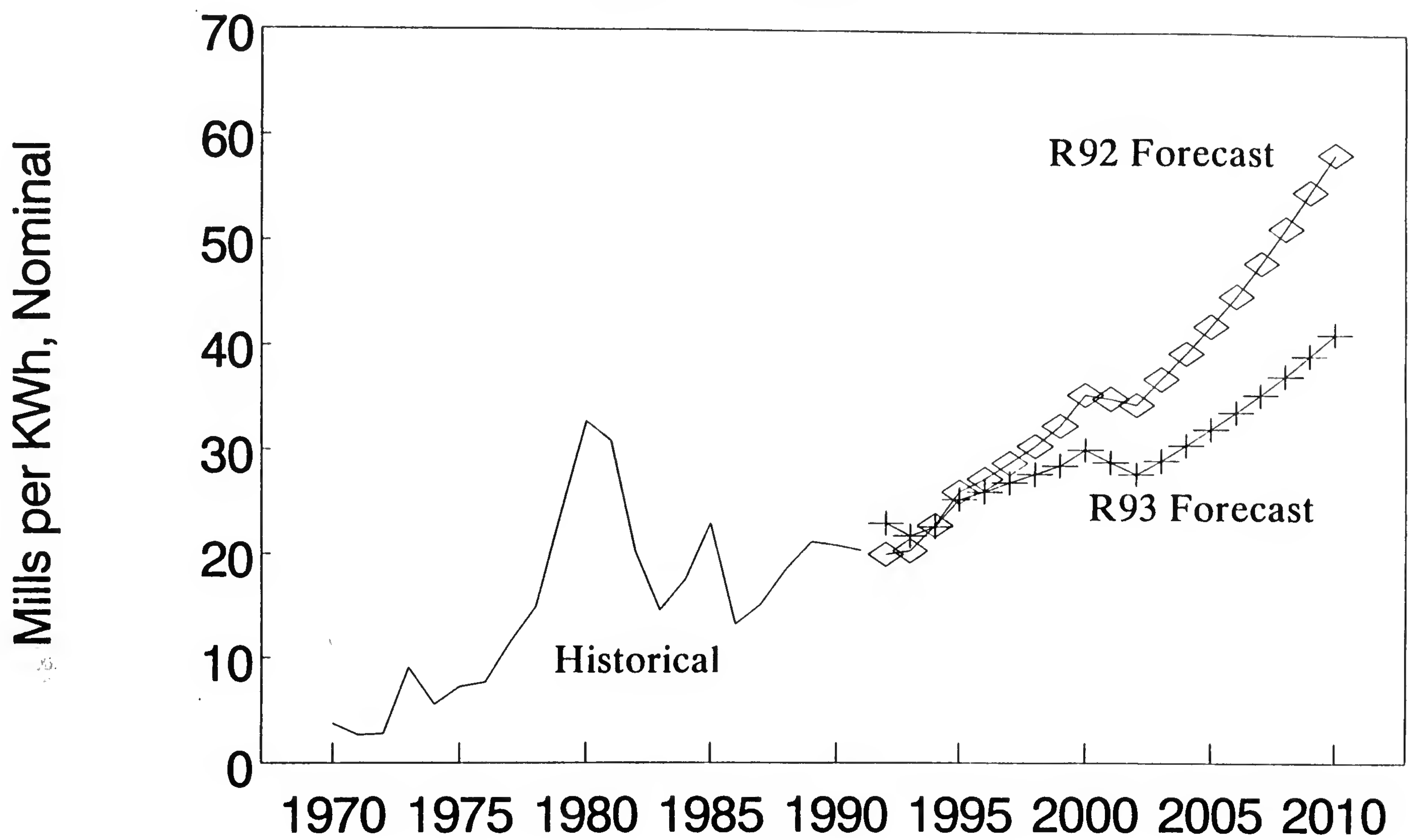


ILLUSTRATION 35

FIRST YEAR AVAILABLE

X = FORCED INTO ALL PLANS IN RUN
1 = AVAILABLE 2001
50 = AVAILABLE 2050

PROSCREEN>R92.UFD>RFP.UFD>BGIPRV.UFD>RESOURCES_AVAILABLE.W20
18-JAN-1993
03:12:04 PM

		RPC = IN / BGI = IN			RPC = OUT / BGI = IN		RPC = OUT / BGI = OUT			
NAME	PRVW ALT #	5A	5AH	5A435	4A	4A NLF435	3A	3A NLF	3ANLF435	2A
RYAN	1	97	97	97	97	97	97	97	97	97
THOMPSON FALLS	4	97	97	97	97	97	97	97	97	97
BIRD PEAKING	5	97	97	97	97	97	97	97	97	97
1/2 WESTMORELAND	11	96	96	96	96	96	96	96	96	96
IDAHO EXCHANGE(50)**	12	X	X	X	X	X	97	97	97	X
IDAHO EXCHANGE(26)**	14	97	97	97	97	97	97	97	97	97
BASIN SUMMER	16	96	96	96	96	96	96	96	96	96
1/2 WESTMORELAND	17	98	98	98	98	98	98	98	98	98
WESTMORELAND	19	50	1	50	50	50	1	50	50	1
TIBER	24	50	50	50	50	50	50	50	50	50
SASA	26	92	92	92	92	92	92	92	92	92
WESTMORELAND	29	97	97	97	97	97	97	97	97	97
STONE B	34	94	94	94	94	94	94	94	94	94
LS POWER	35	96	96	96	96	96	96	96	96	96
STONE C	37	50	50	50	50	50	94	94	94	94
BASIN WINTER	38	X	X	X	96	96	96	96	96	X
WESTMORELAND CT	40	1-97 ON	1-97 ON	1-97 ON	1-97 ON	1-97 ON	2-97 1-98 ON	2-97 1-98 ON	2-97 1-98 ON	2-97 1-98 ON

** NOTE: THE 26 MW IDAHO EXCHANGE MODEL IS AVAILABLE ONLY WHEN THE 50 MW IDAHO EXCHANGE IS ALREADY IN A PLAN. TOGETHER THEY FORM THE 76 MW IDAHO EXCHANGE OPTION.

Phase 2 Risk and Uncertainty

		A	B	C	D	E	F	G	H	I	J	K	L	M	N
RUN # ->		5A	5AH	5A435	4A	4A435NLF	4A435NLF	4A435NLF	3A	3ANLF	2A	2AH	2AL	2ANLF	2ANLF
		W/RP&BOI	W/RP&BOI HIGH FORECAST	W/RP&BOI 435 HYDRO	W/BOI W/O RP	W/BOI W/O RP 435 HY,NEW LF	W/BOI W/O RP 435 HY,NEW LF	W/BOI W/O RP 435 HY,NEW LF	W/O BOI W/O RP	W/O BOI &RP NEW FORECAST	W/O BOI W/RP	W/O BOI W/RP HIGH FORECAST	W/O BOI W/RP LOW FORECAST	W/O BOI W/RP NEW FORECAST	W/O BOI W/RP NEW FORECAST
	Preferred Plan	Lowest TPV 2030 Ttl Soc. Cost Plan	Lowest TPV 2030 Ttl Soc. Cost Plan	Lowest TPV 2030 Ttl Soc. Cost Plan	Lowest TPV 2030 Ttl Soc. Cost Plan	Lowest TPV 2030 Ttl Soc. Cost Plan	Lowest TPV 2030 Ttl Soc. Cost Plan	2nd Lowest TPV 2030 Ttl Soc. Cost Plan	Lowest TPV 2030 Ttl Soc. Cost Plan	Lowest TPV 2030 Ttl Soc. Cost Plan	Lowest TPV 2030 Ttl Soc. Cost Plan	Lowest TPV 2030 Ttl Soc. Cost Plan	Lowest TPV 2030 Ttl Soc. Cost Plan	Lowest TPV 2030 Ttl Soc. Cost Plan	2nd Lowest TPV 2030 Ttl Soc. Cost Plan
	Plan #2B Proview to 2001	Plan #2 Proview to 2004	Plan #12 Proview to 2004	Plan #2 Proview to 2004	Plan #4 Proview to 2004	Plan #2 MOD Proview to 2004	Plan #2 Proview to 2004	Plan #8 Proview to 2004	Plan #1B Proview to 2004	Plan #23 Proview to 2004	Plan #3 Proview to 2004	Plan #7 Proview to 2004	Plan #12 Proview to 2004	Plan #10 Proview to 2004	Plan #24 Proview to 2004
1994	BOI 42MW	BOI 42MW	BOI 42MW	BOI 42MW	BOI 42MW	BOI 42MW	BOI 42MW	BOI 42MW							
1995										Stone B 15MW		Stone B 15MW			
1996	Basin Wntr 98MW StoneB 15MW	Basin Wntr 98MW StoneB 15MW	Basin Wntr 98MW Basin Smr 98MW Stone B 15MW	Basin Wntr 98MW Stone B 15MW	Basin Wntr 98MW	Stone B 15MW	CC#1 46MW Stone B 15MW	CC#1 46MW Stone B 15MW	Basin Wntr 98MW Basin Smr 98MW	Basin Wntr 98MW CC#1 46MW	Basin Wntr 98MW Basin Smr 98MW	Basin Wntr 98MW Basin Smr 98MW CC#1 46MW	Basin Wntr 98MW	CC#1 46MW LS 68MW	Basin Wntr 98MW Basin Smr 98MW CC#1 46MW
1997	T.Falls 41MW Bird 60MW	T.Falls 41MW Bird 60MW	T.Falls 41MW Ryan 43MW Bird 60MW CT 33MW	T.Falls 41MW Ryan 43MW Bird 60MW CT 33MW	T.Falls 41MW Bird 60MW Stone B 15MW	T.Falls 41MW Bird 60MW Basin Wntr 98MW	Bird 60MW Basin Wntr 98MW	T.Falls 41MW Bird 60MW Basin Wntr 98MW	T.Falls 41MW Ryan 43MW Bird 60MW CT 33MW	T.Falls 41MW * Ryan 43MW	T.Falls 41MW Ryan 43MW Bird 60MW Stone B 15MW	T.Falls 41MW Ryan 43MW Bird 60MW CT 33MW	T.Falls 41MW Bird 60MW	Basin Wntr 98MW Stone B 15MW	T.Falls 41MW Bird 60MW
1998	IPC 50MW	IPC 50MW IPC 26MW	IPC 50MW IPC 26MW	IPC 50MW IPC 26MW	IPC 50MW	IPC 50MW IPC 26MW	IPC 50MW IPC 26MW	IPC 50MW	IPC 50MW IPC 26MW	IPC 50MW	IPC 50MW IPC 26MW	IPC 50MW IPC 26MW	IPC 50MW IPC 26MW	IPC 50MW IPC 26MW	IPC 50MW IPC 26MW
1999															
2000						* Ryan 43MW	* Ryan 43MW			Bird 60MW					
2001			CC 92MW									CT 33MW			
2002		* Ryan 43MW			* Ryan 43MW						CT 33MW			* Ryan 43MW	
2003				CT 33MW								CC 92MW			* Ryan 43MW
2004		CT 33MW	CC 92MW	CT 33MW	CT 33MW	CT 33MW	CT 33MW	CT 33MW		CT 33MW	CT 33MW	CT 33MW	CT 33MW	CT 33MW	CT 33MW

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
	5A	5AH	5A435	4A	4A435NLF	4A435NLF	4A435NLF	3A	3ANLF	2A	2AH	2AL	2ANLF	2ANLF
Inc.Ttl.Soc.Cost, M$	Plan #2	Plan #12	Plan #2	Plan #4	Plan #2 MOD	Plan #2	Plan #8	Plan #1B	Plan #23	Plan #3	Plan #7	Plan #12	Plan #10	Plan #24
1991-2030 TPV	2444.35	2729.28	2484.06	2333.27	2423.35	2431.49	2437.98	2360.79	2432.88	2458.63	2737.86	2185.23	2536.51	2542.01
Lvl per Yr	278.44	310.90	282.97	265.79	276.05	276.98	277.72	268.93	277.14	280.07	311.88	248.93	288.94	289.57
Dif From #4A	12.65	45.11	17.18		10.26	11.19	11.93	3.14	11.35	14.28	46.09	-16.86	23.15	23.78
%Diff	4.76%	18.97%	8.46%		3.86%	4.21%	4.49%	1.18%	4.27%	5.37%	17.34%	-8.34%	8.71%	8.95%

* Ryan timed in replacing the original CT. The TPV for these plans include the dollars for a CT, the dollars for Ryan are expected to be about the same

Phase 2 Risk and Uncertainty

	8/22/92		Oct 9, 1992 Run										
	A		B	C	D	E	F	G	H	I	J	K
	Preferred Plan		Lowest TPV 2030 Ttl Soc. Cost Plan	1st Plan "Like #28"	1st Plan W/Ryan	1st Plan W/Ryan & T.Falls	1st Plan W/O Stone B	1st Plan W/Stagged In 46 MW CC's	1st Plan W/LS	1st Plan W/CC @ 92MW	Similar To Plan #142 Ryan v.s. CT	Similar To Plan #96 Ryan v.s. CT
	Plan #28 Proview to 2001		Plan #2 Proview to 2004	Plan #14 Proview to 2004	Plan #6 Proview to 2004	Plan #17 Proview to 2004	Plan #45 Proview to 2004	Plan #49 Proview to 2004	Plan #70 Proview to 2004	Plan #134 Proview to 2004	Plan #96 Proview to 2004	Plan #142 Proview to 2004
1994	BGI 42MW	Fixed->	BGI 42MW	BGI 42MW	BGI 42MW	BGI 42MW	BGI 42MW	BGI 42MW	BGI 42MW	BGI 42MW	BGI 42MW	BGI 42MW
1995												
1996	Basin Wntr 98MW Stone B 15MW	Fixed->	Basin Wntr 98MW Stone B 15MW	Basin Wntr 98MW Stone B 15MW	Basin Wntr 98MW Stone B 15MW	Basin Wntr 98MW Stone B 15MW	Basin Wntr 98MW CC #1 46MW	Basin Wntr 98MW CC #1 46MW	Basin Wntr 98MW Stone B 15MW	Basin Wntr 98MW Stone B 15MW	Basin Wntr 98MW Basin Smr 98MW	Basin Wntr 98MW Basin Smr 98MW
1997	T.Falls 41MW Bird 60MW		T.Falls 41MW Bird 60MW	T.Falls 41MW Bird 60MW	Bird 60MW Ryan 43MW	T.Falls 41MW Bird 60MW	Bird 60MW	Bird 60MW	T.Falls 41MW LS 68MW	Bird 60MW CC 92MW	T.Falls 41MW Bird 60MW Ryan 43MW	T.Falls 41MW Bird 60MW CT 33MW
1998	IPC 50MW	Fixed->	IPC 50MW IPC 26MW	IPC 50MW	IPC 50MW	IPC 50MW	IPC 50MW IPC 26MW	IPC 50MW IPC 26MW	IPC 50MW IPC 26MW	IPC 50MW	IPC 50MW IPC 26MW	IPC 50MW IPC 26MW
1999												
2000						Ryan 43MW						
2001				CT 33MW	CT 33MW							
2002			CT 33MW				CT 33MW	CT 33MW				
2003				CT 33MW	CT 33MW	CT 33MW			CT 33MW			
2004			CT 33MW				CT 33MW	CC #2 46MW	CT 33MW	CT 33MW	CT 33MW	CT 33MW

Inc.Ttl.Soc.Cost, M$	B	C	D	E	F	G	H	I	J	K
	Plan #2	Plan #14	Plan #6	Plan #17	Plan #45	Plan #49	Plan #70	Plan #134	Plan #96	Plan #142
1991-2030 TPV	2444.35	2448.91	2450.86	2458.17	2458.96	2462.68	2465.61	2470.62	2478.02	2479.25
Lvl per Yr	278.44	278.96	279.19	280.02	280.11	280.53	280.87	281.44	282.28	282.42
Dif From #2		0.52	0.74	1.57	1.66	2.09	2.42	2.99	3.84	3.98
%Diff		0.19%	0.27%	0.57%	0.60%	0.75%	0.87%	1.07%	1.38%	1.43%

Phase 2 Risk and Uncertainty

Year	8/22/92		Oct 19, 1992 Run 5AH								
	A		B	C	D	E	F	G	H	I	J
	Preferred Plan		Lowest TPV 2030 Ttl Soc. Cost Plan	1st Plan W/O Stone B	1st Plan W/Ryan Only	1st Plan W/TF Only	1st Plan W/Ryan & T.Falls	1st Plan W/O TF & Ryan	1st Plan W/Stagged In 46 MW CC's	1st Plan W/LS	1st Plan W/CC @ 92MW
	Plan #28 Proview to 2001		Plan #12 Proview to 2004	Plan #30 Proview to 2004	Plan #9 Proview to 2004	Plan #68 Proview to 2004	Same As #12 Proview to 2004	Plan #58 Proview to 2004	Plan #15 Proview to 2004	Plan #26 Proview to 2004	Same As #9 Proview to 2004
1994	BG1 42MW	Fixed->	BG1 42MW	BG1 42MW	BG1 42MW	BG1 42MW	BG1 42MW	BG1 42MW	BG1 42MW	BG1 42MW	BG1 42MW
1995											
1996	Basin Wntr 98MW StoneB 15MW	Fixed->	Basin Wntr 98MW Basin Smr 98MW Stone B 15MW	Basin Wntr 98MW Basin Smr 98MW CC#1 46MW	Basin Wntr 98MW Basin Smr 98MW Stone B 15MW	Basin Wntr 98MW Basin Smr 98MW CC#1 46MW		Basin Wntr 98MW Basin Smr 98MW Stone B 15MW	Basin Wntr 98MW Basin Smr 98MW Stone B 15MW	Basin Wntr 98MW Stone B 15MW LS 68MW	
1997	T.Falls 41MW Bird 60MW		T.Falls 41MW Ryan 43MW Bird 60MW CT 33MW	T.Falls 41MW Ryan 43MW Bird 60MW	Ryan 43MW Bird 60MW CC#1 92MW	T.Falls 41MW Bird 60MW CT 33MW		Bird 60MW CC#1 92MW CT 33MW	Ryan 43MW Bird 60MW CC#1 46MW CT 33MW	T.Falls 41MW Ryan 43MW CT 33MW	
1998	IPC 50MW	Fixed->	IPC 50MW IPC 26MW	IPC 50MW IPC 26MW	IPC 50MW IPC 26MW	IPC 50MW IPC 26MW		IPC 50MW IPC 26MW	IPC 50MW IPC 26MW	IPC 50MW IPC 26MW	
1999											
2000											
2001			CC 92MW	CC 92MW		CT 33MW				CT 33MW	
2002					CT 33MW	CC#2 46MW		CT 33MW	CT 33MW		
2003					CT 33MW			CT 33MW	CT 33MW	CC 92MW	
2004			CC 92MW	CT 33MW	CT 33MW	CT 33MW		CC 92MW	CC#2 46MW		

	B	C	D	E	F	G	H	I	J
Inc.Ttl.Soc.Cost, M$	Plan #12	Plan #30	Plan #9	Plan #68		Plan #58	Plan #15	Plan #26	
1991-2030 TPV	2729.28	2736.15	2732.18	2740.58		2743.23	2734.44	2729.55	
Lvl per Yr	310.90	311.68	311.23	312.19		312.49	311.49	310.93	
Dif From #12		0.78	0.33	1.29		1.59	0.59	0.03	
%Diff		0.25%	0.11%	0.41%		0.51%	0.19%	0.01%	

Phase 2 Risk and Uncertainty

	8/22/92		Oct 19, 1992 Run 5A435							
	A		B	C	D	E	F	G	H	I
	Preferred Plan		Lowest TPV 2030 Ttl Soc. Cost Plan	1st Plan W/Ryan Only	1st Plan W/TF Only	1st Plan W/Ryan & T.Falls	1st Plan W/O Stone B	1st Plan W/Stagged In 46 MW CC's	1st Plan W/LS	1st Plan W/CC @ 92MW
	Plan #28 Proview to 2001		Plan #2 Proview to 2004	Plan #21 Proview to 2004	Plan #27 Proview to 2004	Same As #2 Proview to 2004	Plan #10 Proview to 2004	Plan #11 Proview to 2004	Plan #57 Proview to 2004	Same As #21 Proview to 2004
1994	BGI 42MW	Fixed->	BGI 42MW	BGI 42MW	BGI 42MW	BGI 42MW	BGI 42MW	BGI 42MW	BGI 42MW	BGI 42MW
1995										
1996	Basin Wntr 98MW StoneB 15MW	Fixed->	Basin Wntr 98MW Stone B 15MW	Basin Wntr 98MW Stone B 15MW	Basin Wntr 98MW CC#1 46MW		Basin Wntr 98MW CC#1 46MW	Basin Wntr 98MW Stone B 15MW	Basin Wntr 98MW LS 68 MW	
1997	T.Falls 41MW Bird 60MW		T.Falls 41MW Ryan 43MW Bird 60MW CT 33MW	Ryan 43MW Bird 60MW CC 92MW	T.Falls 41MW Bird 60MW CT 33MW		T.Falls 41MW Ryan 43MW Bird 60MW	T.Falls 41MW Ryan 43MW Bird 60MW CC#1 46MW	T.Falls 41MW Ryan 43MW CT 33MW	
1998	IPC 50MW	Fixed->	IPC 50MW IPC 26MW	IPC 50MW	IPC 50MW IPC 26MW		IPC 50MW IPC 26MW	IPC 50MW IPC 26MW	IPC 50MW IPC 26MW	
1999										
2000										
2001										
2002										
2003			CT 33MW	CT 33MW	CT 33MW		CT 33MW		CT 33MW	
2004			CT 33MW	CT 33MW				CC#2 46MW		

	B	C	D	E	F	G	H	I
Inc.Ttl.Soc.Cost, M$	Plan #2	Plan #21	Plan #27		Plan #10	Plan #11	Plan #57	
1991-2030 TPV	2484.06	2492.34	2495.24		2493.41	2497.13	2509.95	
Lvl per Yr	282.97	283.91	284.24		284.03	284.46	285.92	
Dif From #2		0.94	1.27		1.06	1.49	2.95	
%Diff		0.33%	0.45%		0.38%	0.53%	1.04%	

Phase 2 Risk and Uncertainty

	8/22/92		Oct 12, 1992 Run 4A								
	A		B	C	D	E	F	G	H	I	J
	Preferred Plan		Lowest TPV 2030 Ttl Soc. Cost Plan	1st Plan W/Ryan Only	1st Plan W/Ryan & T.Falls	1st Plan W/O Stone B	1st Plan W/Stagged In 46 MW CC's	1st Plan W/LS	1st Plan W/CC @ 92MW	1st Plan W/Stone C	1st Plan No Bird
	Plan #28 Proview to 2001		Plan #4 Proview to 2004	Plan #5 Proview to 2004	Plan #21 Proview to 2004	Plan #10 Proview to 2004	Plan #42 Proview to 2004	No Plan In RFP Window	No Plan In RFP Window	No Plan In RFP Window	Plan #28 Proview to 2004
1994	BGI 42MW	Fixed ->	BGI 42MW	BGI 42MW	BGI 42MW	BGI 42MW	BGI 42MW				BGI 42MW
1995											
1996	Basin Wntr 98MW StoneB 15MW		Basin Wntr 98MW	Basin Wntr 98MW	Basin Wntr 98MW	Basin Wntr 98MW	CC#146MW				Basin Wntr 98MW
1997	T.Falls 41MW Bird 60MW		T.Falls 41MW Bird 60MW Stone B 15MW	Bird 60MW Ryan 43MW Stone B 15MW	T.Falls 41MW Bird 60MW Stone B 15MW	Bird 60MW CT 33MW	T.Falls 41MW Bird 60MW Ryan 43MW CT 33MW				T.Falls 41MW Stone B 15MW CT 33MW
1998	IPC 50MW	Fixed ->	IPC 50MW	IPC 50MW	IPC 50MW Ryan 43MW	IPC 50MW IPC 26MW	IPC 50MW IPC 26MW				IPC 50MW IPC 26MW Ryan 43MW
1999											
2000											
2001				CT 33MW							
2002			CT 33MW			CT 33MW					
2003					CT 33MW						CT 33MW
2004			CT 33MW	CT 33MW		CC#146MW	CC#146MW				

	B	C	D	E	F	G	H	I	J
Inc.Ttl.Soc.Cost, M$	Plan #4	Plan #5	Plan #21	Plan #10	Plan #42	No Plan	No Plan	No Plan	Plan #28
1991-2030 TPV	2333.27	2337.36	2351.80	2338.74	2386.66				2358.34
Lvl per Yr	265.79	266.26	267.90	266.41	271.87				268.65
Dif From #4		0.47	2.11	0.62	6.08				2.86
%Diff		0.18%	0.79%	0.23%	2.29%				1.07%

Phase 2 Risk and Uncertainty

	8/22/92		Oct 26, 1992 Run 4A435NLF								
	A		B	C	D	E	F	G	H	I	J
	Preferred Plan		Lowest TPV 2030 Tl Soc. Cost Plan	2nd Lowest TPV 2030 Tl Soc. Cost Plan	1st Plan W/Ryan Only	1st Plan W/Ryan & T.Falls	1st Plan W/O Stone B	1st Plan W/Stagged In 46 MW CC's	1st Plan W/LS	1st Plan W/CC @ 92MW	1st Plan No Bird
	Plan #28 Proview to 2001		Plan #2 Proview to 2004	Plan #8 Proview to 2004	Plan #11 Proview to 2004	Plan #21 Proview to 2004	No Plan In RFP Window	Plan #22 Proview to 2004	No Plan In RFP Window	No Plan In RFP Window	Same as #11 Proview to 2004
1994	BG1 42MW	Fixed-->	BG1 42MW	BG1 42MW	BG1 42MW	BG1 42MW		BG1 42MW			
1995											
1996	Basin Watr 98MW StoneB 15MW		CC#1 46MW Stone B 15MW	CC#1 46MW Stone B 15MW	CC#1 46MW Stone B 15MW	CC#1 46MW Stone B 15MW		CC#1 46MW Stone B 15MW			
1997	T.Falls 41MW Bird 60MW		Bird 60MW Basin Watr 98MW	T.Falls 41MW Bird 60MW Basin Watr 98MW	Ryan 43MW Basin Watr 98MW CT 33MW	T.Falls 41MW Bird 60MW Ryan 43MW CT 33MW		T.Falls 41MW Bird 60MW Ryan 43MW CT 33MW			
1998	IPC 50MW	Fixed-->	IPC 50MW IPC 26MW	IPC 50MW	IPC 50MW IPC 26MW	IPC 50MW IPC 26MW		IPC 50MW IPC 26MW			
1999											
2000			CT 33MW								
2001											
2002											
2003					CT 33MW						
2004			CT 33MW	CT 33MW		CT 33MW		CC#2 46MW			

Inc.Ttl.Soc.Cost, M$	B	C	D	E	F	G	H	I	J
	Plan #2	Plan #8	Plan #11	Plan #21		Plan #22			
1991-2030 TPV	2431.49	2437.98	2450.72	2462.03		2465.64			
Lvl per Yr	276.98	277.72	279.17	280.46		280.87			
Dif From #2		0.74	2.19	3.48		3.89			
%Diff		0.27%	0.79%	1.26%		1.40%			

Phase 2 Risk and Uncertainty

	8/22/92	Oct 14, 1992 Run 3A								
	A	B	C	D	E	F	G	H	I	J
	Preferred Plan	Lowest TPV 2030 Tll Soc. Cost Plan	Lowest TPV 2030 Tll Soc. Cost Plan W/O Stone C	1st Plan W/Stone B&C	1st Plan W/Ryan Only	1st Plan W/Ryan & T.Falls	1st Plan W/O Stone B	1st Plan W/Stagged In 46 MW CC's	1st Plan W/LS	1st Plan W/CC @ 92MW
	Plan #28 Proview to 2001	Plan #2 Proview to 2004	Plan #18 Proview to 2004	Plan #8 Proview to 2004	Plan #6 Proview to 2004	Plan #14 Proview to 2004	Same As #2 Proview to 2004	No Plan In RFP Window	No Plan In RFP Window	No Plan In RFP Window
1994	BGI 42MW									
1995										
1996	Basin Watr 98MW StoneB 15MW	Basin Watr 98MW Stone C 38MW	Basin Watr 98MW Basin Smr 98MW	Basin Watr 98MW Stone C 38MW	Basin Watr 98MW Stone C 38MW	Basin Watr 98MW Stone C 38MW				
1997	T.Falls 41MW Bird 60MW	T.Falls 41MW Bird 60MW CT 33MW	T.Falls 41MW Ryan 43MW Bird 60MW CT 33MW	StoneB 15MW Ryan 43MW Bird 60MW CT 33MW	Ryan 43MW Bird 60MW CT 33MW	T.Falls 41MW Bird 60MW CT 33MW				
1998	IPC 50MW	IPC 50MW IPC 26MW	IPC 50MW IPC 26MW	IPC 50MW IPC 26MW	IPC 50MW IPC 26MW	IPC 50MW				
1999										
2000						Ryan 43MW				
2001					CT 33MW					
2002				CT 33MW						
2003		CT 33MW								
2004						CT 33MW				

	B	C	D	E	F	G	H	I	J
Inc.Tll.Soc.Cost, M$	Plan #2	Plan #18	Plan #8	Plan #6	Plan #14		No Plan	No Plan	No Plan
1991-2030 TPV	2336.21	2360.79	2344.10	2343.14	2350.19				
Lvl per Yr	266.13	268.93	267.02	266.91	267.72				
Dif From #2		2.80	0.90	0.79	1.59				
%Diff		1.05%	0.34%	0.30%	0.60%				

Phase 2 Risk and Uncertainty

	8/22/92	Oct 23, 1992 Run 3ANLF								
	A	B	C	D	E	F	G	H	I	J
	Preferred Plan	Lowest TPV 2030 Ttl Soc. Cost Plan	Lowest TPV 2030 RR W/O Stone C	1st Plan W/Stone B&C	1st Plan W/Ryan Only	1st Plan W/Ryan & T.Falls	1st Plan W/O Stone B	1st Plan W/Stagged In 46 MW CC's	1st Plan W/LS	1st Plan W/CC @ 92MW
	Plan #28 Proview to 2001	Plan #2 Proview to 2004	Plan #23 Proview to 2004	Same As #2 Proview to 2004	Plan #6 Proview to 2004	Plan #36 Proview to 2004	Plan #66 Proview to 2004	Plan #29 Proview to 2004	Same As #66 Proview to 2004	No Plan In RFP Window
1994	BGI 42MW									
1995		StoneB 15MW	StoneB 15MW		StoneB 15MW	StoneB 15MW		StoneB 15MW		
1996	Basin Wntr 98MW StoneB 15MW	Basin Wntr 98MW CC#1 46MW	Basin Wntr 98MW CC#1 46MW		Basin Wntr 98MW CC#1 46MW	Basin Wntr 98MW CC#1 46MW	CC#1 46MW LS 68MW	Basin Wntr 98MW CC#1 46MW		
1997	T.Falls 41MW Bird 60MW	Stone C 38MW Bird 60MW	T.Falls 41MW CT 33MW		Stone C 38MW Bird 60MW	T.Falls 41MW Stone C 38MW	T.Falls 41MW Ryan 43MW CT 33MW	Ryan 43MW Stone C 38MW		
1998	IPC 50MW	IPC 50MW	IPC 50MW		IPC 50MW	Ryan 43MW	IPC 50MW IPC 26MW	Bird 60MW		
1999						Bird 60MW				
2000			Bird 60MW		Ryan 43MW					
2001		CT 33MW						CT 33MW		
2002										
2003					CT 33MW					
2004		CT 33MW	CT 33MW		CT 33MW	CT 33MW	CT 33MW	CC#2 46MW		

	B	C	D	E	F	G	H	I	J
Inc. Ttl. Soc. Cost, M$	Plan #2	Plan #23		Plan #6	Plan #36	Plan #66	Plan #29		
1991 – 2030 TPV	2416.69	2432.88		2426.44	2446.73	2457.09	2440.50		
Lvl per Yr	275.29	277.14		276.40	278.71	279.89	278.01		
Dif From #2		1.84		1.11	3.42	4.60	2.71		
%Diff		0.67%		0.40%	1.24%	1.67%	0.99%		

ILLUSTRATION 36

Phase 2 Risk and Uncertainty

	8/22/92		Oct 12, 1992 Run 2A								
	A		B	C	D	E	F	G	H	I	J
	Preferred Plan		Lowest TPV 2030 Ttl Soc. Cost Plan	1st Plan W/Stone C W/46MW CC W/O Stone B	1st Plan W/Stone B&C	1st Plan W/Ryan Only	1st Plan W/Ryan & T.Falls	1st Plan W/O Stone B	1st Plan W/Stagged In 46 MW CC's	1st Plan W/LS	1st Plan W/CC @ 92MW
	Plan #28 Proview to 2001		Plan #3 Proview to 2004	Plan #39 Proview to 2004	Plan #47 Proview to 2004	Plan #25 Proview to 2004	Same As #3 Proview to 2004	Same As #39 Proview to 2004	Plan #50 Proview to 2004	Plan #103 Proview to 2004	No Plan In RFP Window
1994	BGI 42MW										
1995											
1996	Basin Watr 98MW StoneB 15MW	Fixed ->	Basin Watr 98MW Basin Smr 98MW	Basin Watr 98MW CC 46MW Stone C 38MW	Basin Watr 98MW CC 46MW StoneB 15MW	Basin Watr 98MW CC 46MW Stone C 38MW			Basin Watr 98MW CC 46MW Stone C 38MW	Basin Watr 98MW LS Brd 68MW	
1997	T.Falls 41MW Bird 60MW		T.Falls 41MW Ryan 43MW Bird 60MW Stone B 15MW	T.Falls 41MW Bird 60MW	T.Falls 41MW Bird 60MW Stone C 38MW	Ryan 43MW Bird 60MW			T.Falls 41MW Bird 60MW	T.Falls 41MW Ryan 43MW Stone C 38MW	
1998	IPC 50MW	Fixed ->	IPC 50MW IPC 26MW	IPC 50MW IPC 26MW	IPC 50MW	IPC 50MW IPC 26MW			IPC 50MW IPC 26MW	IPC 50MW	
1999											
2000											
2001											
2002			CT 33MW								
2003				CT 33MW	CT 33MW	CT 33MW			CC 46MW	CT 33MW	
2004			CT 33MW							CT 33MW	

	B	C	D	E	F	G	H	I	J
Inc.Ttl.Soc.Cost, M$	Plan #3	Plan #39	Plan #47	Plan #25			Plan #50	Plan #103	
1991-2030 TPV	2458.63	2462.39	2463.51	2464.91			2466.70	2472.36	
Lvl per Yr	280.07	280.50	280.63	280.79			280.99	281.63	
Dif From #3		0.43	0.56	0.72			0.92	1.56	
%Diff		0.15%	0.20%	0.26%			0.33%	0.56%	

PLAN 2AH

ILLUSTRATION 36

Phase 2 Risk and Uncertainty

	8/22/92		Oct 19, 1992 Run 2AH								
	A		B	C	D	E	F	G	H	I	J
	Preferred Plan		Lowest TPV 2030 Ttl Soc. Cost Plan	1st Plan W/O Stone C	1st Plan W/Ryan Only	1st Plan W/TF Only	1st Plan W/Ryan & T.Falls	1st Plan W/O Stone B	1st Plan W/Stagged In 46 MW CC's	1st Plan W/LS	1st Plan W/CC @ 92MW
	Plan #28 Proview to 2001		Plan #3 Proview to 2004	Plan #7 Proview to 2004	Plan #34 Proview to 2004	Plan #30 Proview to 2004	Same As #3 Proview to 2004	Same As #34 Proview to 2004	Plan #6 Proview to 2004	Same As #34 Proview to 2004	Same As #34 Proview to 2004
1994	BG1 42MW										
1995			Stone B 15MW	Stone B 15MW	Stone C 38MW	Stone B 15MW			Stone B 15MW		
1996	Basin Wntr 98MW StoneB 15MW	Fixed->	Basin Wntr 98MW Basin Smr 98MW CC#1 46MW	Basin Wntr 98MW Basin Smr 98MW CC#1 46MW	Basin Wntr 98MW LS 68 MW	Basin Wntr 98MW Basin Smr 98MW CC#1 46MW			Basin Wntr 98MW Basin Smr 98MW CC#1 46MW		
1997	T.Falls 41MW Bird 60MW		T.Falls 41MW Ryan 43MW Bird 60MW Stone C 38MW	T.Falls 41MW Ryan 43MW Bird 60MW CT 33MW	Ryan 43MW CC 92MW	T.Falls 41MW Bird 60MW Stone C 38MW CT 33MW			T.Falls 41MW Ryan 43MW Bird 60MW CT 33MW		
1998	IPC 50MW	Fixed->	IPC 50MW IPC 26MW	IPC 50MW IPC 26MW	IPC 50MW	IPC 50MW IPC 26MW			IPC 50MW IPC 26MW		
1999											
2000			CT 33MW		CT 33MW	CT 33MW					
2001				CT 33MW	CT 33MW	CT 33MW			CT 33MW		
2002			CT 33MW								
2003			CT 33MW	CC 92MW	CT 33MW	CC 92MW			CC#2 46MW		
2004			CC 92MW	CT 33MW	CC 92MW				CC 92MW		

	B	C	D	E	F	G	H	I	J
Inc.Ttl.Soc.Cost, M$	Plan #3	Plan #7	Plan #34	Plan #30			Plan #6		
1991-2030 TPV	2733.28	2737.86	2736.66	2743.85			2738.87		
Lvl per Yr	311.36	311.88	311.74	312.56			311.99		
Dif From #3		0.52	0.39	1.20			0.64		
%Diff		0.17%	0.12%	0.39%			0.20%		

Phase 2 Risk and Uncertainty

	8/22/92	Oct 22, 1992 Run 2AL							
	A	B	C	D	E	F	G	H	I
	Preferred Plan	Lowest TPV 2030 Ttl Soc. Cost Plan	1st Plan W/Ryan & T.Falls	1st Plan W/Ryan Only	1st Plan W/Stone B	1st Plan W/LS	1st Plan W/46 MW CC	1st Plan W/Stagged In 46 MW CC's	1st Plan W/CC @ 92MW
	Plan #28 Proview to 2001	Plan #12 Proview to 2004	Plan #30 Proview to 2004	Plan #107 Proview to 2004	Plan #105 Proview to 2004	Plan #101 Proview to 2004	Plan #87 Proview to 2004	NO PLAN IN RFP WINDOW	NO PLAN IN RFP WINDOW
1994	BG1 42MW								
1995									
1996	Basin Watr 98MW StoneB 15MW	Basin Watr 98MW	Basin Watr 98MW	Basin Watr 98MW	Basin Watr 98MW	Basin Wntr 98MW	Basin Watr 98MW		
1997	T.Falls 41MW Bird 60MW	T.Falls 41MW Bird 60MW	T.Falls 41MW Bird 60MW	Ryan 43MW LS 68MW CT 33MW	T.Falls 41MW Ryan 43MW Stone 15 MW CC 46MW CT 33MW	T.Falls 41MW Ryan 43MW LS 68MW CT 33MW	T.Falls 41MW Ryan 43MW Bird 60MW CC 46MW		
1998	IPC 50MW	IPC 50MW IPC 26MW	IPC 50MW IPC 26MW						
1999									
2000			Ryan 43MW						
2001									
2002									
2003									
2004		CT 33MW							

	B	C	D	E	F	G	H	I
Inc.Ttl.Soc.Cost, M$	Plan #12	Plan #30	Plan #107	Plan #105	Plan #101	Plan #87		
1991-2030 TPV	2185.23	2202.03	2260.00	2254.63	2256.11	2241.02		
Lvl per Yr	248.93	250.84	257.44	256.83	257.00	255.28		
Dif From #12		1.91	8.52	7.90	8.07	6.35		
%Diff		0.77%	3.42%	3.18%	3.24%	2.55%		

Phase 2 Risk and Uncertainty

	8/22/92	Oct 21, 1992 Run 2ANLF							
	A	B	C	D	E	F	G	H	J
	Preferred Plan	Lowest TPV 2030 Ttl Soc. Cost Plan	2nd Lowest TPV 2030 Ttl Soc. Cost Plan	1st Plan W/Ryan Only	1st Plan W/T.Falls Only	1st Plan W/Ryan & T.Falls	1st Plan W/Stagged In 46 MW CC's	1st Plan W/LS	1st Plan W/CC @ 92MW
	Plan #28 Proview to 2001	Plan #10 Proview to 2004	Plan #24 Proview to 2004	Plan #31 Proview to 2004	Same As #24 Proview to 2004	Plan #63 Proview to 2004	Plan #12 Proview to 2004	Same As #10 Proview to 2004	No Plan In RFP Window
1994	BGI 42MW								
1995									
1996	Basin Watr 98MW StoneB 15MW	CC#1 46MW LS 68MW	Basin Watr 98MW Basin Smr 98MW CC#1 46MW	CC#1 46MW LS 68MW		Basin Watr 98MW Basin Smr 98MW CC#1 46MW	CC#1 46MW LS 68MW		
1997	T.Falls 41MW Bird 60MW	Basin Watr 98MW Stone B 15MW	T.Falls 41MW Bird 60MW	Basin Watr 98MW Stone B 15MW		T.Falls 41MW Ryan 43MW Stone B 15MW	Basin Wntr 98MW Stone B 15MW		
1998	IPC 50MW	IPC 50MW IPC 26MW	IPC 50MW IPC 26MW	IPC 50MW		IPC 50MW IPC 26MW	IPC 50MW IPC 26MW		
1999				Ryan 43MW					
2000									
2001									
2002		CT 33MW					CT 33MW		
2003			CT 33MW			CT 33MW			
2004		CT 33MW	CT 33MW	CT 33MW		CT 33MW	CC#2 46MW		

	B	C	D	E	F	G	H	J
Inc. Ttl. Soc. Cost, M$	Plan #10	Plan #24	Plan #31		Plan #63	Plan #12		
1991 – 2030 TPV	2536.51	2542.01	2547.96		2551.77	2542.25		
Lvl per Yr	288.94	289.57	290.25		290.68	289.60		
Dif From #10		0.63	1.30		1.74	0.65		
%Diff		0.22%	0.45%		0.60%	0.23%		

ILLUSTRATION 37

Decision Rule Matrix

Score Sheet

		Appendix C	Plan (1 = Preferred Plan)												
		Page #	2	2X	4	7	28	56	66	92	101	113	124	133	142
1	Surplus or Def														
2	Ann aMW x Jan MW	8		1			1	1				1			
3	W aMW x S aMW	9					1								
4															
5	SUM		0	1	0	0	2	1	0	0	0	1	0	0	0
6															
7	Customer Concerns														
8	IncRR x C (LT)	11					1		1	1	1	1	1	1	
9	IncRR x C (ST)	12	1	1					1						
10	W/O Eco (LT)	13					1					1			
11	W/O Eco (ST)	14	1	1			1					1			
12															
13	SUM		2	2	0	0	3	0	2	1	1	3	1	1	0
14															
15	Owner Concerns														
16	ROE x NI	18					1	1			1				
17															
18	SUM		0	0	0	0	1	1	0	0	1	0	0	0	0
19															
20	Customer & Owner														
21	RReq x ROE	21	1	1	1	1	1	1	1	1	1				
22	C/kwh x ROE	22					1			1	1			1	1
23															
24	SUM		1	1	1	1	2	1	1	2	2	0	0	1	1
25	Subtotal		3	4	1	1	8	3	3	3	4	4	1	2	1
26															
27	Uncertainty														
28	Load Uncertainty														
29	Load Loss, ROE	24 a							1		1	1	1	1	1
30	Flexibility	28	1			1									
31															
32															
33	Fuel Uncertainty														
34	Diversity	31					1			1					
35	High Fuel	33	1	1	1	1	1	1		1	1				
36															
37															
38	DSM Uncertainty														
39	Resource Flexibility	37	1		1	1	1						1		
40															
41															
42	Off-System Price														
43	+10% & -10%	41		1	1	1	1			1	1				
44															
45															
46	Uncertainty sum		3	2	3	4	4	1	1	3	3	1	2	1	1
47															
48	Envir Impact	43	1	1	1	1	1	1							
49															
50	SUM		1	1	1	1	1	1	0	0	0	0	0	0	0
51															
52	DEE	47					1								
53															
54	SUM		0	0	0	0	1	0	0	0	0	0	0	0	0
55															
56	Plan:		2	2X	4	7	28	56	66	92	101	113	124	133	142
57	TOTAL SUM		7	7	5	6	14	5	4	6	7	5	3	3	2
58	NBR TIMES FIRST		1	1	1	2	7	2	0	1	2	1	0	0	0

RESOURCE NEGOTIATION ACTION PLAN

Resource Planning

Level 1

> The resources in this category are the most desired resources because they appear plan 28 and most all of the R&U Phase 2 plans.

> The total amount of resource is not sufficient to meet the base case forecast need for resource.

>

Resources:
E+, Energy Efficiency Plus, 116 MW by 2001
Basin Winter Purchase, 98 MW
Idaho Power Company Seasonal Exchange, 50 MW
Thompson Falls Upgrade, 41 MW
Bird, 60 MW

Level 2

> Second level priority.

> These resources provide the flexibility to address future resource need uncertainty.

> Some, not all, of the resources in this category are required to meet the base case load foecast need for resource.

> All resources in this level should be moved into active negotiations

> Final selection of the set of resources depends upon RP Chem, BGI, New Load Forecast, 435MW Hydro, MHD, T&D efficiency improvements, hydro secondary firming, etc., assumptions.

>

Resource	Status
Ryan, 43 MW	Included in base plan at this time as an optioned "In" resource.
Stone B, 15 MW	Continue evaluation of issues, potential option "In" resource in base plan.
Id Power Ex, 26MW	Not included in base plan, highly prefered alternative in R&U.
Basin Smr, 98 MW	Complements the larger IPCo exchange.
Bird Firming, 60MW	The new energy load forecast is higher, firming the hydro secondary a low cost alternative.
LS Bird, 68 MW	Negotiate the Bird lost opportunity option, consider other factors also.
Tiber, 5MW	Consider as option of need greater than expected or 435 MW hydro off set.

Level 3

> Third level priority.

> Should not eliminate at this time, but negotiations should be at a minimum.

> These resources are least likely to be included in the optimum plans when ALL factors are considered.
(i.e. Load forecast + T&D efficiency + hydro 435 MW + MHD + Hydro Secondary)

>

Resources:	
Westmoreland, 46 MW	A BGI replacement with the new load forecast before considering other possible changes.
Westmoreland, 92 MW	Even under high load conditions doesn't come in until after 2001.
Stone C, 38MW	Low preference because of the rate impact (i.e. August Utility Officer presentation).

THE MONTANA POWER COMPANY

ENERGY LOAD FORECAST & RESOURCE TABULATIONS (aMW)

02/19/93 R93EXPND WK3			1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
ANNUAL ENERGY LOAD, AVG MW			982	1007	1033	1058	1078	1096	1111	1123	1134	1144	1154	1164	1175	1189	1203
E+			−8	−16	−27	−40	−52	−64	−74	−83	−90	−95	−98	−102	−105	−108	−111
T&D EFF. IMPROVEMENTS				−1	−1	−2	−2	−3	−4	−5	−5	−5	−6	−6	−6	−6	−6
PACIFICORP SALE			10	10	10												
BLACK HILLS SALE			2														
WWP SALE			36	26													
BPA SALE			27	53	53	27											
RPCHEM REMOVE						−52	−52	−52	−52	−52	−52	−52	−52	−52	−52	−52	−52
NET TOTAL LOAD			1049	1079	1068	991	972	977	981	983	987	992	998	1004	1012	1023	1034
EXISTING RESOURCE, AVG MW			1066	1084	1040	950	902	902	902	902	902	902	902	902	902	902	902
HYDRO @ CRITICAL WATER			335	335	335	335	335	335	335	335	335	335	335	335	335	335	335
CORETTE			122	122	122	122	122	122	122	122	122	122	122	122	122	122	122
COLSTRIP 1,2&3			435	435	435	435	435	435	435	435	435	435	435	435	435	435	435
INTERRUPTIBLE LOAD			3	3	3												
BPA(PK/EN)			−29	−29	−29	−29	−29	−29	−29	−29	−29	−29	−29	−29	−29	−29	−29
WNP#1			67	67	67	29											
IDAHO EXCHANGE			0														
IDAHO PURCHASE			50	50	50	19											
BASIN PURCHASE			44	62	18												
EXISTING QF			39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
+ OR −			17	5	−28	−41	−70	−75	−79	−81	−85	−90	−96	−102	−110	−121	−132
FUTURE @ CRIT WATER	aMW	MW	5	4	32	93	191	199	198	202	202	203	203	203	206	206	209
BGI	47	52			27	47	47	47	47	47	47	47	47	47	47	47	47
FLINT CREEK	1	1		1	1	1	1	1	1	1	1	1	1	1	1	1	1
MILLTOWN	1	1										1	1	1	1	1	1
MADISON	3	2				1	3	3	3	3	3	3	3	3	3	3	3
HAUSER	3	3								3	3	3	3	3	3	3	3
RAINBOW	9	7					1	9	9	9	9	9	9	9	9	9	9
FW BIRD (1)	65	74					65	65	65	65	65	65	65	65	65	65	65
THOMPSON FALLS (2)	15	41				13	15	15	15	15	15	15	15	15	15	15	15
IPC EXCHANGE (2)	−1	50		−1	−1	−1	−1	−1	−1	−1	−1	−1	−1	−1	−1	−1	−1
BASIN ELEC COOP (2)	42	98				15	42	42	42	42	42	42	42	42	42	42	42
RYAN (3)	1	43									1	1	1	1	1	1	1
STONE CONTAINER (4)	13	15				13	13	13	13	13	13	13	13	13	13	13	13
COMBUSTION TURBINE	3	33													3	3	3
COMBUSTION TURBINE	3	33															3
O.S.S. LOSS			5	4	5	4	5	5	4	5	4	4	4	4	4	4	4
+ OR −			22	9	4	52	121	124	119	121	117	113	107	101	96	85	77
ALTERNATIVE RESOURCES (5)					32	36	40	40	40	40	40	40	40	40	40	40	40

1. Replacing MPC's life optimization has been recognized by a re−powering of the facility. Negotiations with LS Power Corp continue.
2. Status could change as a result of additional negotiations and/or additional evaluation.
3. Option resource, timing will vary with the need for resource, FERC must recognize timing flexibility, status may change as a result of further evaluation.
4. Option resource, status of the resource pending further evaluation and negotiations.
5. Quantities for this resource are uncertain and are not included in the balance. This category may include wind, solar, MHD, fuel switching, etc.

THE MONTANA POWER COMPANY

JANUARY PEAK LOAD FORECAST & RESOURCE TABULATIONS (MW)

02/19/93 R93EXPND.WK3			1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
WINTER PEAK LOAD, JANUARY MW			1439	1475	1511	1546	1573	1599	1621	1640	1656	1671	1685	1700	1716	1740	1763
E+			−6	−15	−26	−41	−55	−70	−84	−96	−107	−114	−121	−128	−133	−139	−144
T&D EFF. IMPROVEMENTS				−1	−2	−4	−5	−6	−7	−9	−10	−11	−12	−12	−12	−12	−12
PACIFICORP SALE			10	10	10												
BLACK HILLS SALE			30														
WWP SALE			0	0													
BPA SALE			0	0	0	0											
RPCHEM REMOVE						−74	−74	−74	−74	−74	−74	−74	−74	−74	−74	−74	−74
NET TOTAL LOAD			1473	1469	1493	1427	1439	1449	1456	1461	1465	1472	1478	1486	1497	1515	1533
EXISTING RESOURCE, MW			1549	1499	1499	1431	1277	1277	1277	1277	1277	1277	1277	1277	1277	1277	1277
HYDRO @ CRITICAL WATER			435	435	435	435	435	435	435	435	435	435	435	435	435	435	435
CORETTE			160	160	160	160	160	160	160	160	160	160	160	160	160	160	160
COLSTRIP 1,2&3			537	537	537	537	537	537	537	537	537	537	537	537	537	537	537
INTERRUPTIBLE LOAD (6)			68	68	68												
BPA(PK/EN)			100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
WNP#1			79	79	79	79											
IDAHO EXCHANGE			50														
IDAHO PURCHASE			75	75	75	75											
BASIN PURCHASE			0	0	0												
EXISTING QF			45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
FORCED OUTAGE RESERVE			186	185	188	180	181	183	183	184	185	185	186	187	189	191	193
+ OR −			−110	−155	−182	−176	−343	−355	−362	−368	−373	−380	−387	−396	−409	−429	−449
FUTURE @ CRIT WATER	aMW	MW	6	56	56	123	338	346	344	349	391	392	391	392	425	425	458
BGI	47	52			0	52	52	52	52	52	52	52	52	52	52	52	52
FLINT CREEK	1	1		1	1	1	1	1	1	1	1	1	1	1	1	1	1
MILLTOWN	1	1										1	1	1	1	1	1
MADISON	3	2					2	2	2	2	2	2	2	2	2	2	2
HAUSER	3	3								3	3	3	3	3	3	3	3
RAINBOW	9	7						7	7	7	7	7	7	7	7	7	7
FW BIRD (1)	65	74					74	74	74	74	74	74	74	74	74	74	74
THOMPSON FALLS (2)	15	41				0	41	41	41	41	41	41	41	41	41	41	41
IPC EXCHANGE (2)	−1	50		50	50	50	50	50	50	50	50	50	50	50	50	50	50
BASIN ELEC COOP (2)	42	98				0	98	98	98	98	98	98	98	98	98	98	98
RYAN (3)	1	43									43	43	43	43	43	43	43
STONE CONTAINER (4)	13	15				15	15	15	15	15	15	15	15	15	15	15	15
COMBUSTION TURBINE	3	33													33	33	33
COMBUSTION TURBINE	3	33															33
O.S.S. LOSS			6	5	5	5	5	6	4	6	5	5	4	5	5	5	5
+ OR −			−104	−99	−126	−53	−5	−9	−18	−19	18	12	4	−4	16	−4	9
ALTERNATIVE RESOURCES (5)					40	45	50	50	50	50	50	50	50	50	50	50	50

1. Replacing MPC's life optimization has been recognized by a re−powering of the facility. Negotiations with LS Power Corp continue.
2. Status could change as a result of additional negotiations and/or additional evaluation.
3. Option resource, timing will vary with the need for resource, FERC must recognize timing flexibility, status may change as a result of further evaluation.
4. Option resource, status of the resource pending further evaluation and negotiations.
5. Quantities for this resource are uncertain and are not included in the balance. This category may include wind, solar, MHD, fuel switching, etc.
6. At system input; previous value of 64 MW at customer meter.

Appendix B

Computer Modeling Methodology

Computer Modeling Tools

PROSCREEN II is a computer software system developed by Energy Management Associates, Inc. (EMA) to support electric and gas utility decision analysis and corporate planning. MPC uses PROSCREEN II and other planning models as comprehensive planning tools to evaluate hundreds of alternatives, and to address the effects of uncertainty on business decisions. PROSCREEN II uses dynamic programming to optimize demand-side and supply-side resources portfolios. Using a single, integrated software system for ILCP analysis makes ILCP more manageable, ensures consistency in data assumptions, and provides credible, auditable results.

MPC has various PROSCREEN II application modules currently incorporated into the ILCP process: 1) Load Forecast Adjustment (LFA); 2) Generation and Fuel (GAF); 3) Capital Expenditure and Recovery (CER); 4) Financial Reporting and Analysis, and Class Revenue (FIR & CRM); 5) PROVIEW (PRV); and 6) Scenario Analysis (SCE). The LFA, GAF, CER and FIR modules can operate independently, or as an integrated package with automatic information transfer between modules. The modules are capable of processing data as detailed as one hour to as aggregate as total present value for a 50 year study.

The Load Forecasting Adjustment (LFA) module is designed to represent the load and DSM areas of utility planning. The LFA can accept data as detailed as hourly sales energy, or as general as monthly sales energy. Group data can represent a single large customer. Any number of Groups sum into Class data. Company data are the sum of all Classes. The LFA adjusts all input data for consistency before passing the class sales or aggregate load on to other modules. DSM programs modify sales on an hourly basis, if so input. The flexibility of the LFA allows various load growth scenarios to be tested for their affects on production cost and rates. Scenarios considering marketing, DSM, high, base and low loads can all be examined efficiently. Losses between sales and the generators are input explicitly for each load group.

The Generation and Fuel (GAF) module is designed to represent the cost of serving the utility load. The GAF is designed to serve the hourly load transferred from the LFA. There are three types of resource models available in the GAF: 1) Non-dispatchable; 2) Pump storage; and 3) Dispatchable. These three types of resources are modeled to simulate actual utility operation practices. The GAF is capable of developing production costs for up to five different hydro energy levels (water years), with appropriate probability to simulate actual non-median production costs. The non-dispatchable resources modify the load transferred from the LFA without consideration of cost. This is done because these resources typically represent firm contracts and/or low cost hydro. The pumped storage logic captures the benefits of this technology. The detailed dispatch logic optimizes the costs of serving the remaining load with dispatchable thermal units, while continually keeping track of such things as unit commitment, and economy interchange market opportunities (spot market). Emergency energy is supplied to account for the forced outage characteristics of all units.

The Capital Expenditure and Recovery (CER) module is designed to represent the construction area of utility planning. The CER models multi-year construction costs, AFUDC, taxes, insurance and inflation. The capital and operating revenue requirements are detailed by both project and system level. The data are aggregated and passed, along with production costing data to the Financial Reporting and Analysis (FIR) module.

The Financial Reporting and Analysis (FIR) and the Class Revenue (CRM) Modules are designed to represent the financial area of utility planning. The FIR takes capital and expense revenue requirements and properly accounts for their affects on the customer, owner, and financial status of MPC. Such items as return on equity, debt service requirements, rates by customer class, earnings per share, and other financial variables are calculated and reported. Rate case logic provides rate case timing and effectiveness. The Class Revenue Module (CRM) is designed to analyze long range strategy and the implications of utility plans on customer classes and customer rates.

PROVIEW is a dynamic programming module capable of creating scenarios (resource plans) by selecting from a menu of different supply-side and demand-side resources. These resource plans will meet the planning criteria and will consist of every possible combination of all resources. Hundreds of combinations are created and ranked to provide MPC with a comprehensive economic analysis of all possible ways to serve customer demand.

Scenario Analysis (SCE) is a module that builds customized reports showing only the information (variables) defined by the user. MPC has found this module and the flexible input control system of PROSCREEN II very useful for screening purposes.

Computer Modeling Assumptions

Load Forecast Adjustment Module (LFA)

The LFA module used in the competitive bid analysis is capable of modeling 168 hour typical weeks for all 12 months of the year. The monthly MPC system sales energy and peak are input, as well as the 168 hour load shape. LFA will adjust sales data for losses before providing the GAF with the load requirements at the generator terminals. DSM programs can be entered at this same level of detail, if it is available. MPC was able to input all load data in a 168 hour format.

The LFA module contained the following load information:

1. Aggregate MPC system sales were based on the '*1992 Load Forecast and Integrated Least Cost Resource Plan*', with detailed hourly loads for 168 hours per month for the time period 1992 to 2030.

2. DSM savings were modeled with detailed hourly loads for 168 hours per month in 8 programs:

   Residential Standard Acquisition Rate
   Residential Accelerated Acquisition Rate

Commercial Standard Acquisition Rate
Commercial Accelerated Acquisition Rate
Industrial Standard Acquisition Rate
Industrial Accelerated Acquisition Rate
Contract Industrial Standard Acquisition Rate
Contract Industrial Accelerated Acquisition Rate

In MPC's analysis, one of each of the following were included (both with detailed hourly loads for 168 hours per month):

Stone "B" RFP Bid resource (a load reduction model was used)
Stone "C" RFP Bid Resource (a load reduction model was used)

Also included in the LFA are the customer costs and company costs for each program. The LFA was built using hourly information for each of these load groups. Losses were included in the analysis, and represent the difference between the generator and the customer's meter for each of the above load groups.

Generation and Fuel Module (GAF)

The GAF module used in the competitive analysis is capable of accepting load from the LFA, and dispatching resources to serve that load. The GAF uses a load duration curve method to determine how to serve the load in the most economic and realistic fashion, taking into account maintenance and forced outages.

The model must have sufficient resources committed each day to serve daily peak loads.

The GAF used 3 water years, each representing the energy and capacity characteristics of MPC's hydro system under critical, median, and high water conditions. Each of these water years is assigned a probability of occurrence and the final production cost is the expected value of the 3 water year production costs.

Finally, the model can take advantage of any surplus energy available for sale into the off-system economy market (i.e., the spot market). Proper modeling of the spot market involves hourly price profiles for every month of every year in the study. In addition, the model can buy energy from the spot market to displace a higher cost native resource. The model can also specify transmission limits between the utility and the economy market. The remainder of this section describes GAF methods.

The chronological load from the LFA is first sorted in the GAF by magnitude to arrive at a load duration curve. The area under this curve represents the energy in 1 week for a given month. The maximum point on this curve is the monthly peak for the given month. Weekly results are multiplied by the number of weeks in the month to get monthly results, with those being summed to arrive at annual results.

The load duration curve is first modified by fixed energy resources such as firm transactions (sales and purchases) and hydro resources. The various modelling techniques available allow

the user to modify the load duration curve to simulate the following chronological modifications:

1. Peak Shave Purchase

   These transactions (and peak shave hydro) reduce the magnitude of the utility load during the peak load hours and therefore reduces the difference between the minimum and the maximum load by reducing the maximum load.

2. Baseload (flat)

   These transactions (and run of river hydro) increase (if a sale) or decrease (purchase and hydro) the magnitude of the utility load equally for every hour. The maximum capacity of these types of transactions does not influence the amount of reduction/addition to the load. The two important variables are hours per month and total energy available for load modification. These types of load modifiers takes into consideration the capacity of the given transaction or hydro when the load is modified. That is to say that a 100 MW peak shave purchase with 24,800 MW hours of energy will reduce the load in a 31 day month by roughly 8 hours per day. However a 50 MW, 24,800 MW hours version of the same type of load modifier would reduce the load for roughly 16 hours per day.

3. Hourly

   This type transaction allows explicit input of hourly MW load modification.

4. Pumped Storage

   The load duration curve that remains after all transactions and hydro are dispatched is further modified by pumped storage. The amount of weekly pumped storage pumping and generation is determined by comparing the cost of pumping to that of generating. For example, a pumped storage project may fill its pond by operating as a pump at night (thereby utilizing low cost base load resources that may not be as heavily loaded at night) and as a generator during the day to displace a more expensive resource (such as combustion turbine).

The remaining load duration curve represents the load required to be served by the dispatchable (or commonly called "thermal") resources. These resources do not have a fixed energy output. They are fully operated when they are more economic than other resources, and are not operated at full output if there are sufficient quantities of less expensive sources of energy available.

Thermal units are modeled in two segments. Generally, the first segment of a number of the least expensive units will be started and run to be ready to meet the upcoming peak load. The second segment of the units that are on-line (and the first segment of the units not on-line) will be compared to each other and to alternative sources of energy (i.e., the spot market) to see which is the cheapest way to serve the remainder of the load duration curve. Finally, any energy available from the native resources that can be economically sold on the spot market is

sold.

The model uses a probabilistic dispatch to determine how much energy each month will not be available because of unexpected (forced) outages. This energy is then served with higher cost replacement energy (termed "emergency energy").

MPC's existing resources are modeled in PROSCREEN as thermal units, run-of-river hydro (all of MPC hydro except part of Kerr) or as peak shave hydro (part of Kerr). Montana Power also has some existing contracts that are modeled as one of the 4 types mentioned above.

Almost all of the future resources included in the production costing study to determine the optimal resource plan were modeled as baseload (flat) resources. The most notable exceptions are:

1. The Ryan addition was modeled as a peak shave hydro.

2. The Thompson Falls addition was modeled as a peak shave hydro.

3. Combustion turbines and combined cycle machines from various bidders were modeled as dispatchable thermal resources, when dispatchability was specified, otherwise, baseload.

4. There was one pump storage bid resource modeled.

5. The Idaho exchange extension was a baseload purchase and as an hourly sale.

Capital Expenditure Recovery Module (CER)

The CER accepts information from the various other modules. For example, the CER accepts operating costs from the GAF and combines these costs with the construction costs in the CER to develop incremental revenue requirements. The capital costs from MPC's long range construction budget are input into the CER along with such items as project book life (ie. 36 year book life for thermal units), project tax life (ie. 20 years standard tax life), Allowance for Funds Used During Construction (AFUDC) rates, property tax rates, inflation, and construction starting and ending dates. The CER processes and reports information by project, project class and total aggregate ("system reports"). Reports produce such information as total expenditures, plant additions, book depreciation, book value, operation and maintenance costs, and revenue requirements. Various outputs are then passed to the FIR for financial analysis.

Financial Reporting and Analysis Module (FIR)

The FIR is capable of accepting information from the various other modules such as sales by customer class from the LFA and incremental revenue requirements from the CER and will process it along with user defined inputs in such areas as debt, equity, taxes, rates, balance sheet information, capital structure and various other financial information. It then processes this information into class and company rates based on class and company sales (including sales impacted by conservation programs), as well as stockholder measures (such as return on equity)

and a host of standard financial reports and ratios.

PROVIEW

PROVIEW is a module, capable of creating all possible combinations of user specified resources to meet a given planning criteria. Due to the large amount of hydro power in Montana Power's resource stack, MPC uses critical water planning as its planning criteria. Critical water planning calls for having resources available that will meet the load, even under the worst water conditions.

PROVIEW uses dynamic analysis to deterministically arrange all resources to produce resource plans with enough energy and capacity to satisfy the planning criteria. Additional inputs to PROVIEW cause it to reject plans with excessive energy and capacity, as well as eliminating plans that do not provide adequate reliability, or plans that fail the planning criteria. Mutually inclusive, or exclusive resources can be so flagged, as well as resources which are dependent on one another, such as a staged project.

The dynamic programming logic within PROVIEW continually analyzes the cost of continuing a given plan from one year to the next. For instance, assume that in 1996, plan #123 includes a given stack of resources plus 1 combustion turbine. Further assume that plan #124 contains the same given set of resources, yet does not have the combustion turbine (CT). Assuming both plans meet the planning criteria, PROVIEW would keep both plans and use them as seeds for plans it will build in 1997.

When PROVIEW begins creating plans in 1997, it may see that plan #123 (with CT) meets the planning criteria in 1997 with no changes from 1996. Thus it keeps plan #123 intact. However, as it begins to deterministically change plan #124, it arrives at the state where plan #124 plus a CT meets the planning criteria, thus making plan #124 identical to plan #123 (in 1997). PROVIEW decides, on an economic basis, that since it arrived at the same plan (in 1997) via two different routes, one of the routes can be eliminated. PROVIEW then uses economics to eliminate either plan #123 or #124.

PROVIEW uses both production and capital costs in its decision process. For instance, a high capital resource may have low operating costs (ie. hydro plant), and a low cost resource may have high operating costs (ie. combustion turbine). A fair comparison of these resources or resources with different lives, requires that the value of the capital vs. operating costs and the different life resources be captures, even if the life of the resource exceeds the planning horizon. The different capital costs and resource lives are captured by PROVIEW end-effects logic.

Input Assumptions

The assumptions used in the dynamic supply-side and demand-side optimization analysis included the following.

1. The base case load forecast from the March 1992 "Load Forecast and Integrated Least Cost Resource Plan" was used.

2. RFP, MPC, and Other resources were used to fill the need for resource during the bid window from 1996-2000.

3. If deficiencies occurred beyond 2000, enough resource priced at avoided costs was added to match the resources to the load forecast.

4. To reduce the surplus existing after the bid window, the load was allowed to grow to 2004. After 2004 the load was held constant.

5. End effects for various resource lives were addressed through a study period from 1991 through 2030.

6. Need for resource used critical water planning criteria with hydro capability at 335 average MW annual energy and 489 MW January peak.

7. The economics for each resource plan were computed using average water hydro capability of 385 average MW annual energy and 489 MW January peak.

8. Societal total costs includes the cost of the project adjusted by MPC's environmental externality adjustment factor, debt equivalent equity for purchase power and contribution by customers associated with demand-side resources acquisition.

9. The cost of the resource was supplied by the resource sponsor and, if appropriate, adjusted to common indices.

10. Environmental impacts were internalized by multiplying the cost of the resource by MPC's Environmental Externality Adjustment Factor (EEAF).

11. Debt Equivalent Equity (DEE) for purchase power resources were computed from the fixed cost of the resource and applied to the EEAF adjusted cost of the resource.

12. MPC, RFP, and Other future resources were replaced at the end of their contract or book life at avoided costs.

13. J.E. Corette Plant, Colstrip 1, 2, and 3 were allowed to operate beyond the end of their book lives.

14. An extension of MPC's peak for energy exchange, which ends in 2001, with the Bonneville Power Administration was assumed.

Appendix C

Introduction

The Risk and Uncertainty Analysis includes studying plan costs, plan surplus or deficiency, customer concerns, owner concerns and 14 uncertainties. This appendix provides the detail for the Risk and Uncertainty Analysis as discussed in Section 6.5.2. This uncertainty information appears exactly as it was understood at the time of the Risk and Uncertainty Analysis. Each section outlined on the Index of this appendix begins with graphs and is followed by a narrative. For example, the discussion for the load risk and uncertainty graph that appears on page 24, is on page 26. The results from these various risk and uncertainty studies were incorporated into the Decision Rule matrix used in the Decision Rule Analysis. See Illustration 37 and Section 6.5.3 Summaries of the 14 uncertainties studied, and a brief section on modeling assumptions (See Appendix B for further detail) are discussed below.

Plan Costs

Pages 1 through 6 represent graphs of the cost of the 13 plans and various comparisons. Observations on each graph appear on page 7.

Plan Surplus or Deficiency

A graphic description of the surplus or deficiency of the 13 plans in the year 2000 appears on pages 8 and 9. The narrative portion of these two graphs appear on page 10.

Customer Concerns

Pages 11 through 16 focus on customer concerns such as rates or incremental revenue requirements, and examines customer concerns under various conditions. A written summary of the graphs appear on page 17.

Owner Concerns

Pages 18 and 19 illustrate each resource plan with respect to owner concerns. The observations on these graphs appear on page 20.

Customer and Owner Concerns

Pages 20 and 21 look at the combined concerns of customer and owner, with a summary on page 23.

Load Uncertainty

On page 24 and 24a, the quantifiable uncertainty is addressed by examining the consequences of the addition or loss of a large load to each of the 13 plans. Changes to each resource plan return on equity resulting from load additions (denoted by a "+") and the loss of a large load (denoted by a "-") are displayed. The load addition was a high load factor 40 MW load and the

load loss was a 74 MW interruptible load. The results show that resource flexibility is important to both MPC customers and investors. A discussion of the non-quantifiable load uncertainty and resource flexibility start on pages 26 and 28, respectively.

Fuel Uncertainty

Generally, the resources do not have significant fuel uncertainty. A discussion of the fuel uncertainty for each resource appears on page 29. On page 31, the fuel mix by resource plan is displayed. On page 32-34, the uncertainty associated with high fuel escalation rates is quantified.

Demand-side Resource Cost V.S. Quantity Uncertainty

The consequences of paying 100% of the demand-side resource costs and acquiring 75% of the resource (100/75) were quantified and compared to the base case (BC) for each plan appear on pages 35-38. The graph show that total costs would increase under the 100/75 assumption. The 75/75 scenario is also displayed on the graph.

Economy Sales Uncertainty

Since MPC's need is for peaking resource, all resource plans have surplus power available for sale into the economy market. The revenues generated from the economy market sales reduce the total revenue requirements. The sensitivity of the resource plan to off-system sales price is a quantifiable risk. Pages 39-42 explore the economy sales uncertainty. On page 41, the resource plans that lie below the line that slopes to the upper right hand corner make more revenue under good off-system sales price than they lose under poor off-system sales price.

Environmental Uncertainty

The resource plan is weighted environmental externality adjustment factor (EEAF) was computed by weighing each future resource's EEAF by the cost of the resource within each plan. Plans with an EEAF of 1.0 would have very low environmental impact. Page 43 provides a graph of the plans EEAF. All plans have low plan EEAF with 6 of the plans having a very low plan EEAF. Page 44 includes discussion of the non-quantifiable risk and the environmental uncertainty by resource.

Transmission Uncertainty

Page 46 describes the transmission uncertainty. Each resource appears to have no major transmission problems. However, large resources located on the east end of MPC system may cause increased losses. Resources located on the west end of MPC system will help voltage support, but will probably not cause a deferral of planned transmission investments.

Plan Debt Equivalent Equity Uncertainty

The resource plan is weighted debt equivalent equity (DEE) was computed by weighing each of the future resources' DEE by the cost of the resource. Plans with the lowest DEE could have the lowest exposure. Page 47 provides a graph of the plans DEE. In the graph, two plans

appear to have the greatest risk and one plan has the least risk.

Reliability Uncertainty

A discussion of resource reliability appears on page 49. All resources come from an existing resource or proven technology with established reliability.

Technical Uncertainty

Generally all resource plans are technically sound. Page 50 provides a discussion of technical uncertainty.

Resource Cost Uncertainty

Starting on page 51 a discussion of the resource cost uncertainty begins. The cost uncertainty associated with each resource was analyzed. As can be expected, each resource has its own unique twists which must be explored during negotiations should the resource reach the negotiation stage. This section provided some information regarding each resource cost uncertainty.

EEAF Magnitude Uncertainty

This uncertainty addresses the question of which resources would be selected (or not selected) if MPC used a different EEAF value. In addition to the plans developed with MPC's EEAF, plans were built with no adjustment for environmental externalities (EEAF of 1.0) and with a higher weight for air emissions (New York EEAF). The New York EEAF was discussed in section 6.4.3.1. A summary of the results appears on page 53 followed by a more detailed summary on page 55. This analysis was completed before all 13 of the final resource plans had been selected, so some of the final plans did not receive this analysis. However, all the resources were evaluated through this analysis and inferences can be made about the other plans. The results show that the same resources would have been selected in the Static Analysis and that there is some sensitivity of resource selection in the Dynamic Analysis.

Demand-Side Resource (SSSS and AAAA) Uncertainty

The quantity, price, and rate of acquisition for the SASA demand-side resource is MPC's best estimate at this time. MPC used the SSSS and the AAAA rate of acquisition to understand the resource flexibility that is needed in the SASA plan to move to either the SSSS or AAAA rate of acquisition. A summary of the results appear on page 53 followed by a more detailed summary on page 56. This analysis was completed before all 13 of the final resource plans had been selected, so some of the final plans did not receive this analysis. However, all the resources were evaluated through this analysis and inferences can be made about the other plans. Generally, moving to the SSSS demand-side resource causes resources to be added sooner and moving to the AAAA resource eliminates highest cost resources first.

No Debt Equivalent Equity Uncertainty

MPC used a DEE adjustment to account for the risk associated with purchase power contracts.

A summary of the impact the DEE had on resource selection appears on page 53. A more detailed summary appears on page 57. This analysis was completed before all 13 of the final resource plans had been selected, so some of the final plans did not receive this analysis. However, all the resources were evaluated through this analysis and inferences can be made about the other plans. Generally, the DEE did influence resource selection.

Expected Water Plan Uncertainty

An analysis of the resource selection using expected water logic for the hydro system appears on page 54. A more detailed summary appears on page 58. This analysis was completed before all 13 of the final resource plans had been selected, so some of the final plans did not receive this analysis. However, all the resources were evaluated through this analysis and inferences can be made about the other plans. Generally, the same resource plans would have been developed with the possibility of different resource timing.

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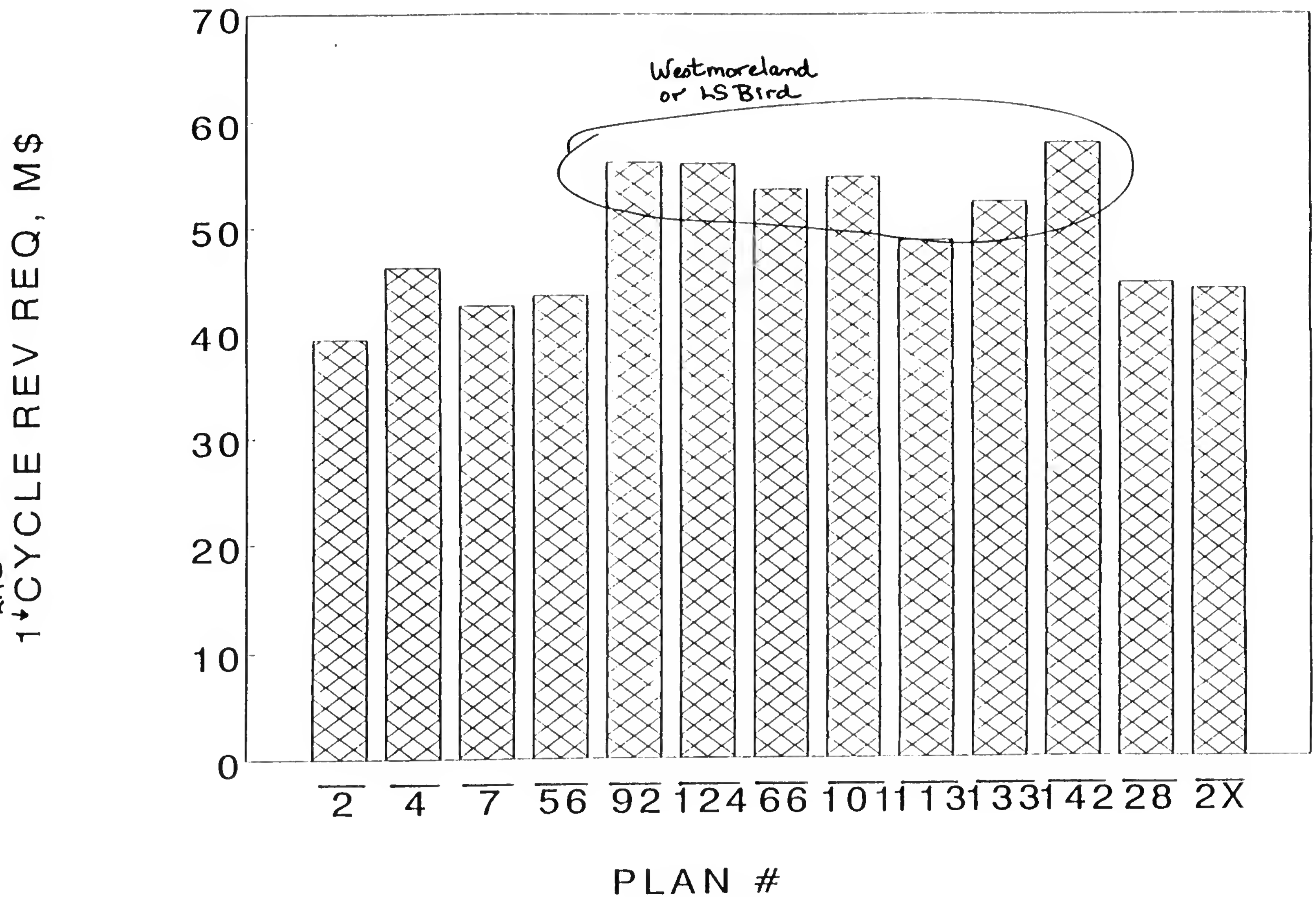
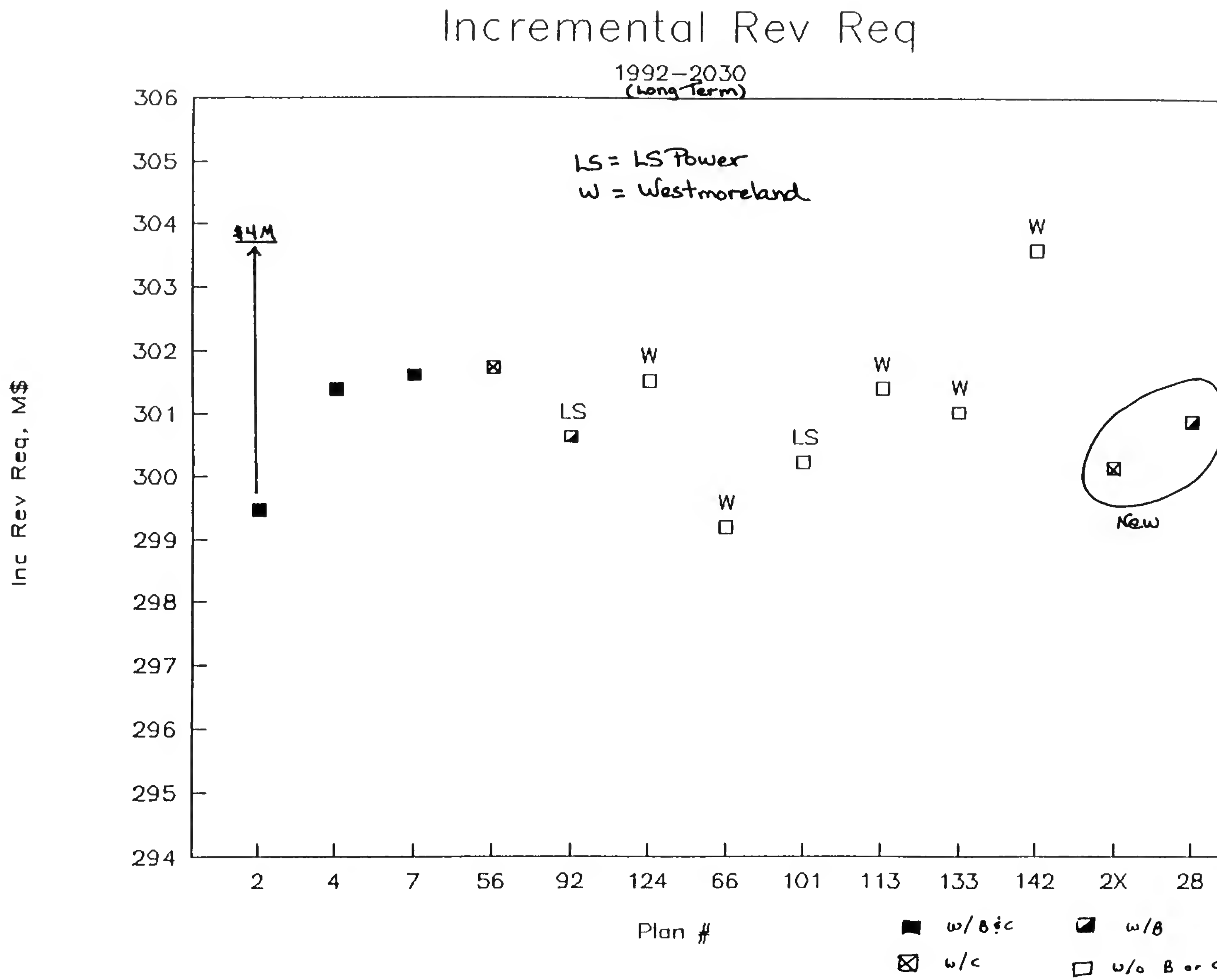
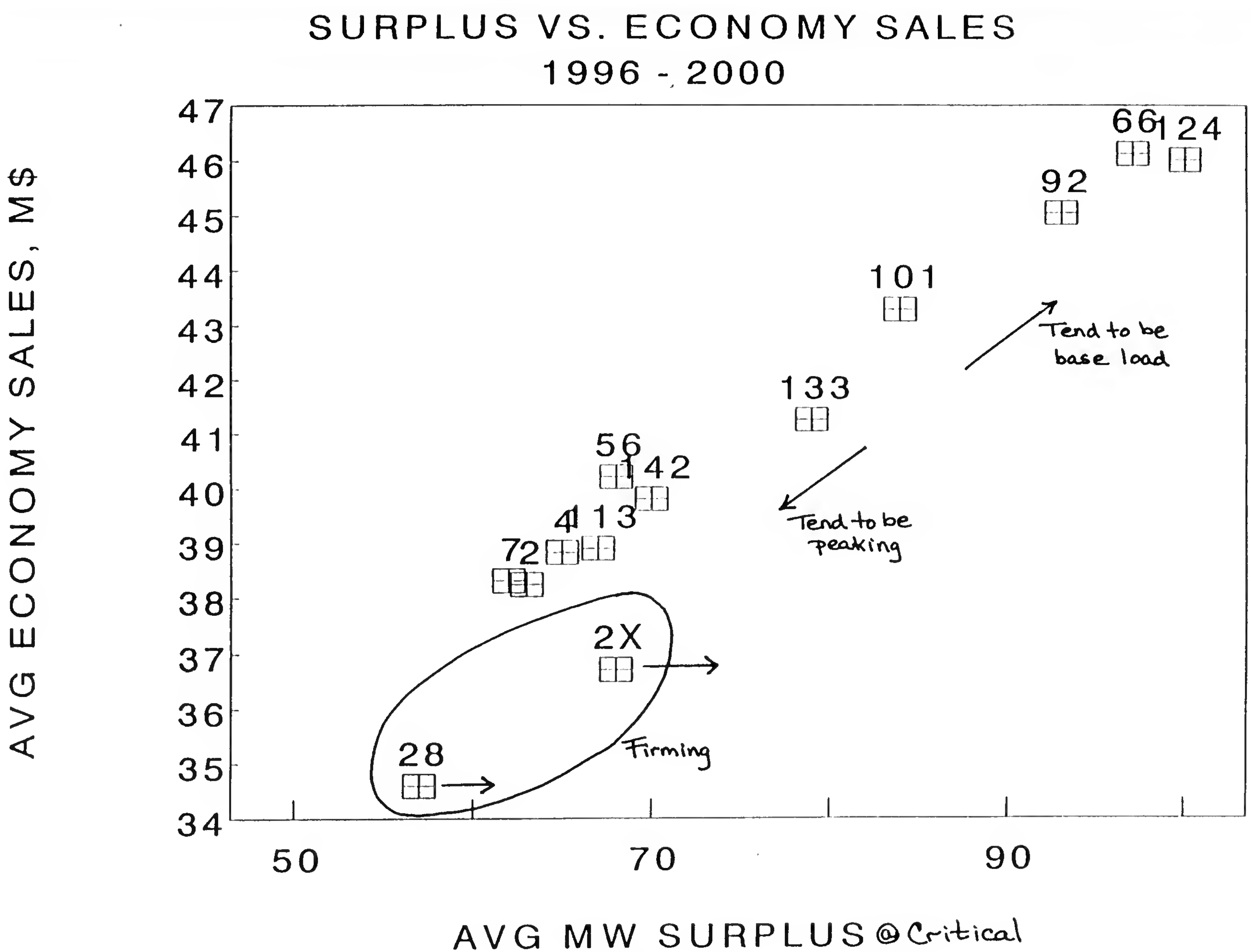
LEVELIZED NEW RFP RESOURCE COSTS



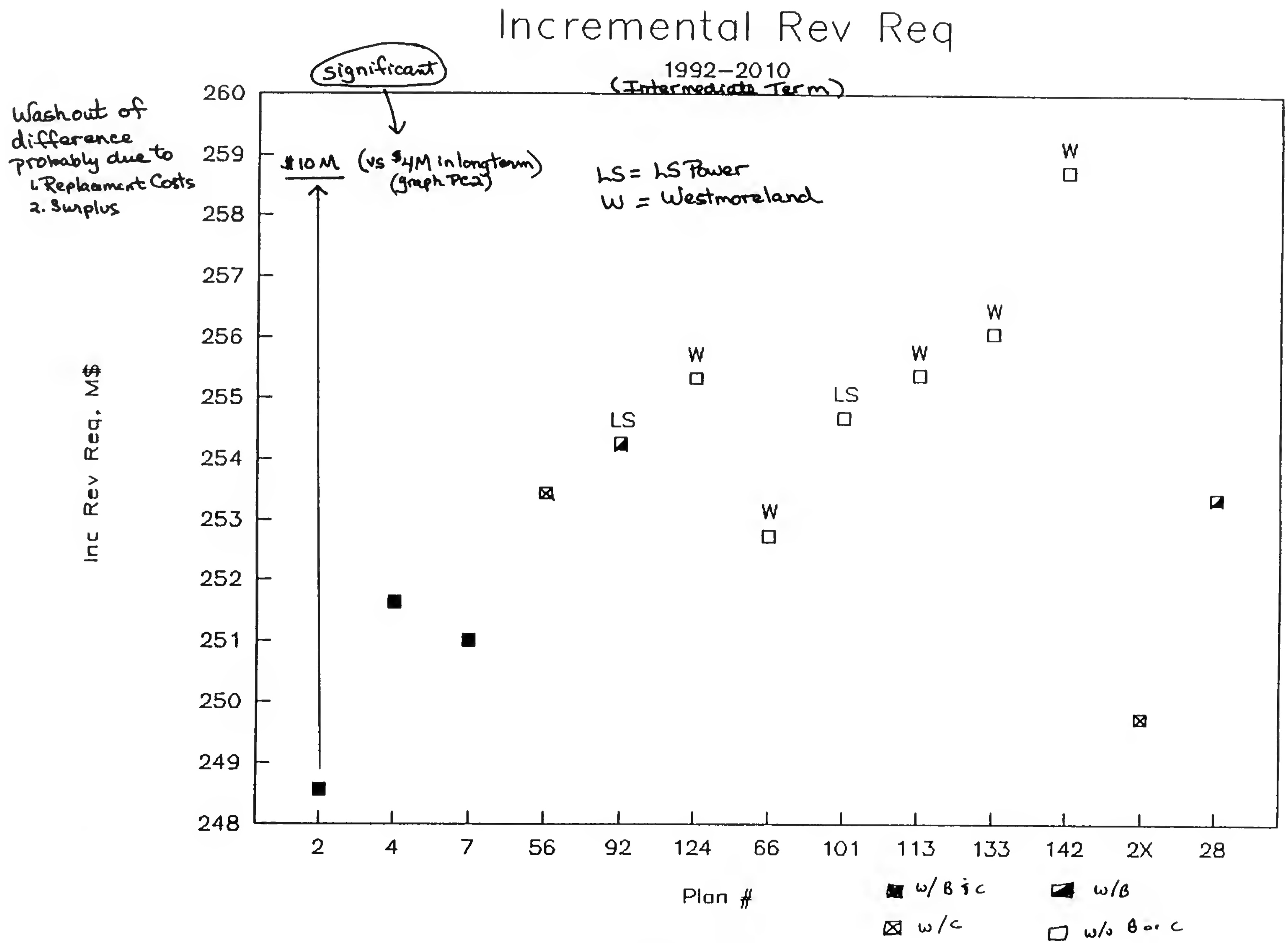
GRAPH PC1 ↖ relates to write up


Incremental Rev Req
1992–2030
(Long Term)
LS = LS Power
W = Westmoreland
$4M
Inc Rev Req, M$
306
305
304
303
302
301
300
299
298
297
296
295
294
LS
W
LS
W
W
W
W
New
2
4
7
56
92
124
66
101
113
133
142
2X
28
Plan #
w/B & c
w/B
w/c
w/o B or c

GRAPH PC2

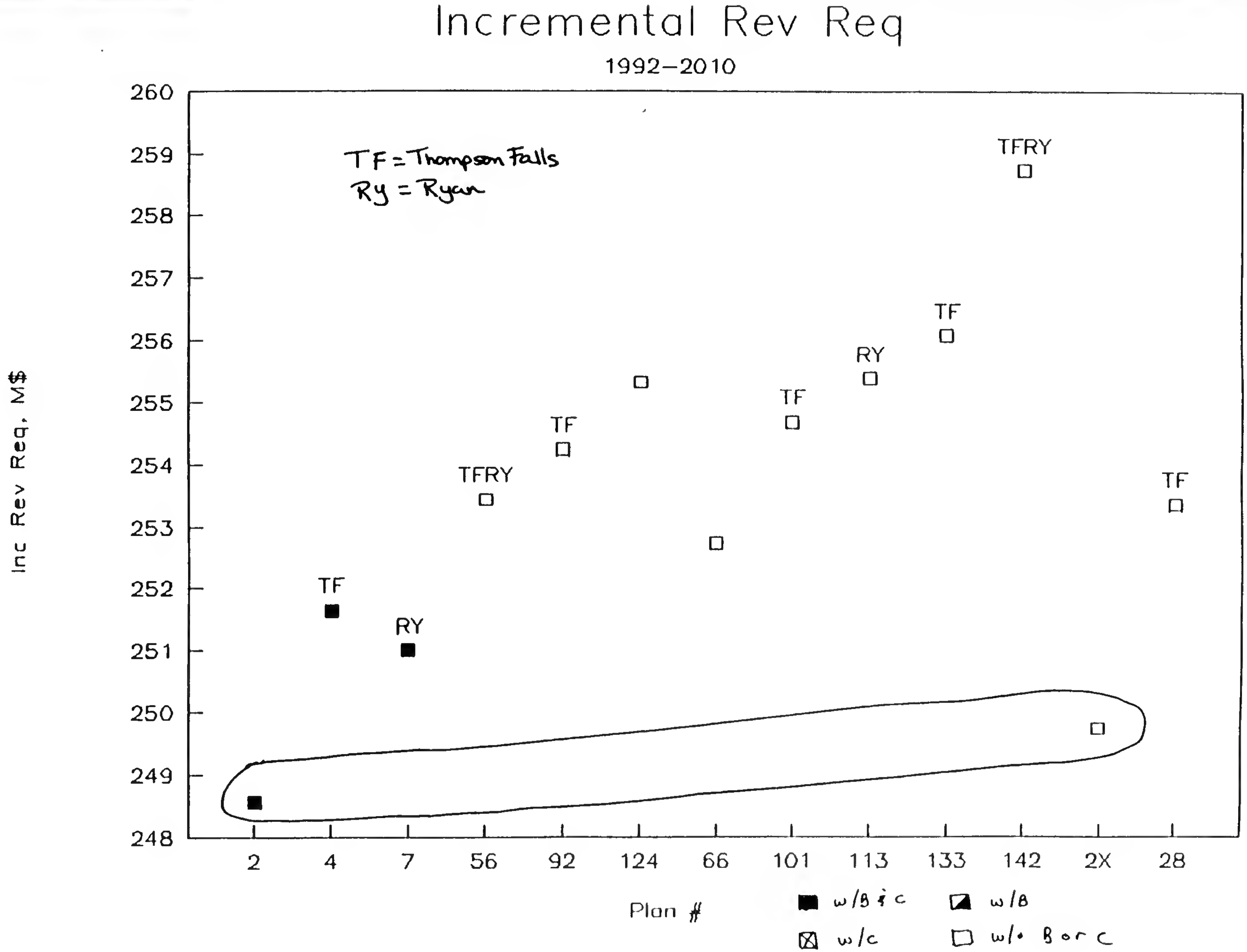

SURPLUS VS. ECONOMY SALES
1996 - 2000
AVG ECONOMY SALES, M$
47
46
45
44
43
42
41
40
39
38
37
36
35
34
50
70
90
AVG MW SURPLUS @Critical
66
124
92
101
133
56
142
4
113
72
2X
28
Tend to be base load
Tend to be peaking
Firming

GRAPH PC3



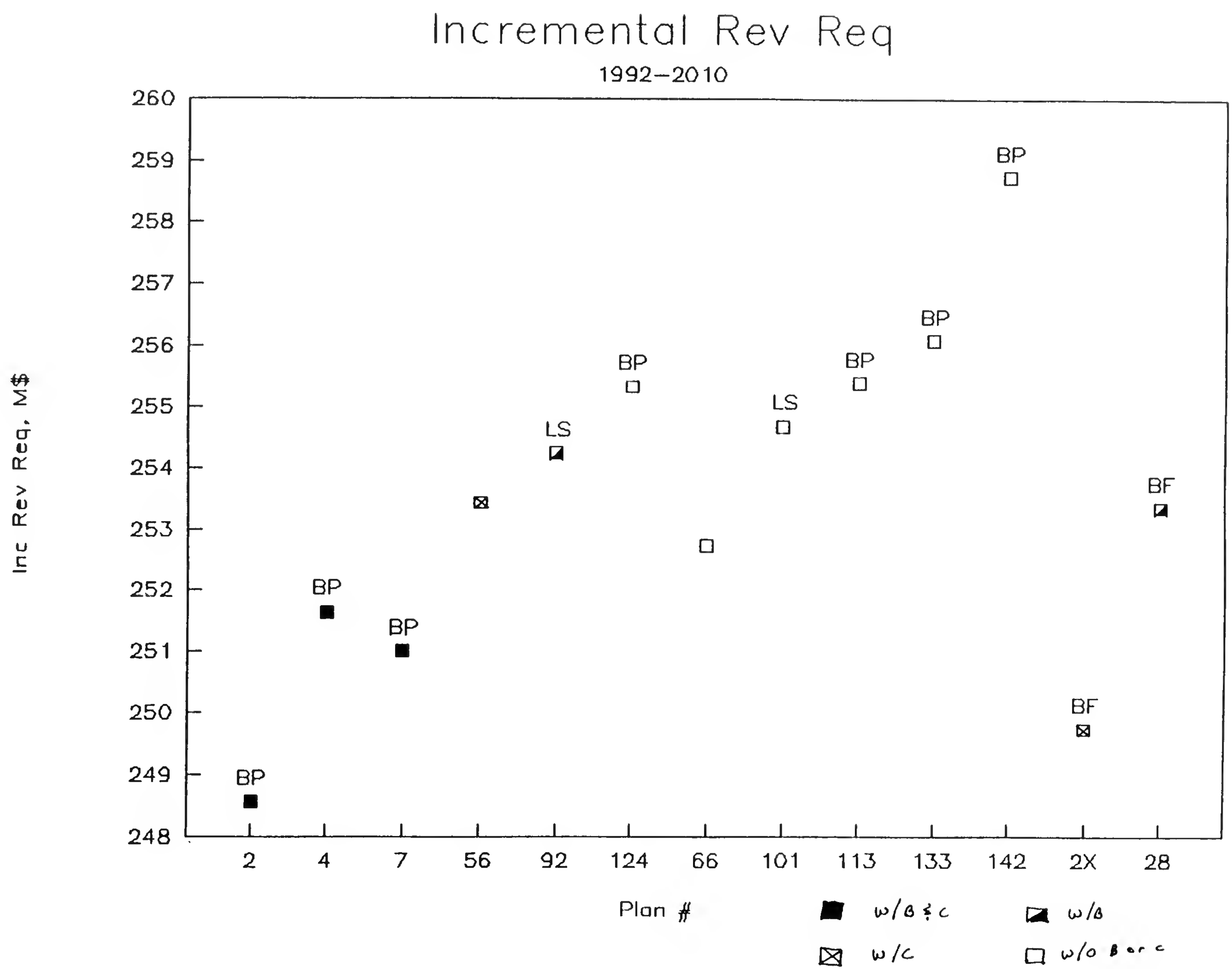
Incremental Rev Req
1992–2010
(Intermediate Term)
Washout of difference probably due to
1. Replacement Costs
2. Surplus
Significant
$10 M
(vs $4M in longterm) (graph PC2)
LS = LS Power
W = Westmoreland
Inc Rev Req, M$
260
259
258
257
256
255
254
253
252
251
250
249
248
2
4
7
56
92
124
66
101
113
133
142
2X
28
Plan #
LS
W
W
LS
W
W
W
w/ B & C
w/ B
w/ C
w/o B or C

GRAPH PC4



Incremental Rev Req
1992–2010
Inc Rev Req, M$
260
259
258
257
256
255
254
253
252
251
250
249
248
TF = Thompson Falls
Ry = Ryan
TFRY
TF
RY
TF
TF
TFRY
TF
TF
RY
2
4
7
56
92
124
66
101
113
133
142
2X
28
Plan #
w/B & c
w/B
w/c
w/o B or C

GRAPH PC5


Incremental Rev Req
1992–2010
Inc Rev Req, M$
260
259
258
257
256
255
254
253
252
251
250
249
248
BP
BP
BP
LS
BP
LS
BP
BP
BP
BF
BF
2
4
7
56
92
124
66
101
113
133
142
2X
28
Plan #
w/B & C
w/B
w/C
w/o B or C

GRAPH PC6

OBSERVATIONS

GRAPH # PC1 Levelized new RFP Resource Costs

Plans 2, 4, 7, 56, 28 and 2X have lowest levelized annual life cycle cost. There is a distinct difference in new unit cost (levelized) between plans which meet the need with peaking resources (2, 4, 7, 56, 28, 2X) and plans which include a large base load unit (92, 124, 66, 101, 113, 133, 142).

GRAPH # PC2 Incremental Revenue Requirements

Plans 66, 101, 133, 92, 124, 113 relative improvement in long term incremental revenue requirement is a result of: (1) higher economy sales revenue; (2) base load resource generally have longer life; and (3) replacement cost for short life peak resource may be high.

GRAPH # PC3 Surplus vs. Economy Sales

Plan 28's (hydro firming) long term incremental revenue requirement is least dependent on economy sales revenue. Plans 124, 66, 92 have the greatest surplus energy which results in the greatest economy sales. Plans 28 and 2X are hydro firming with minimum dispatch on Bird for off system sales.

GRAPH # PC4 Incremental Revenue Requirement (LS & Westmoreland)

Intermediate Term (1992 - 2010) removes the impact of replacement costs and may lose site of the longer term value of long life resources. A clear trade-off shows lower total cost with Stone, and higher total cost without Stone.

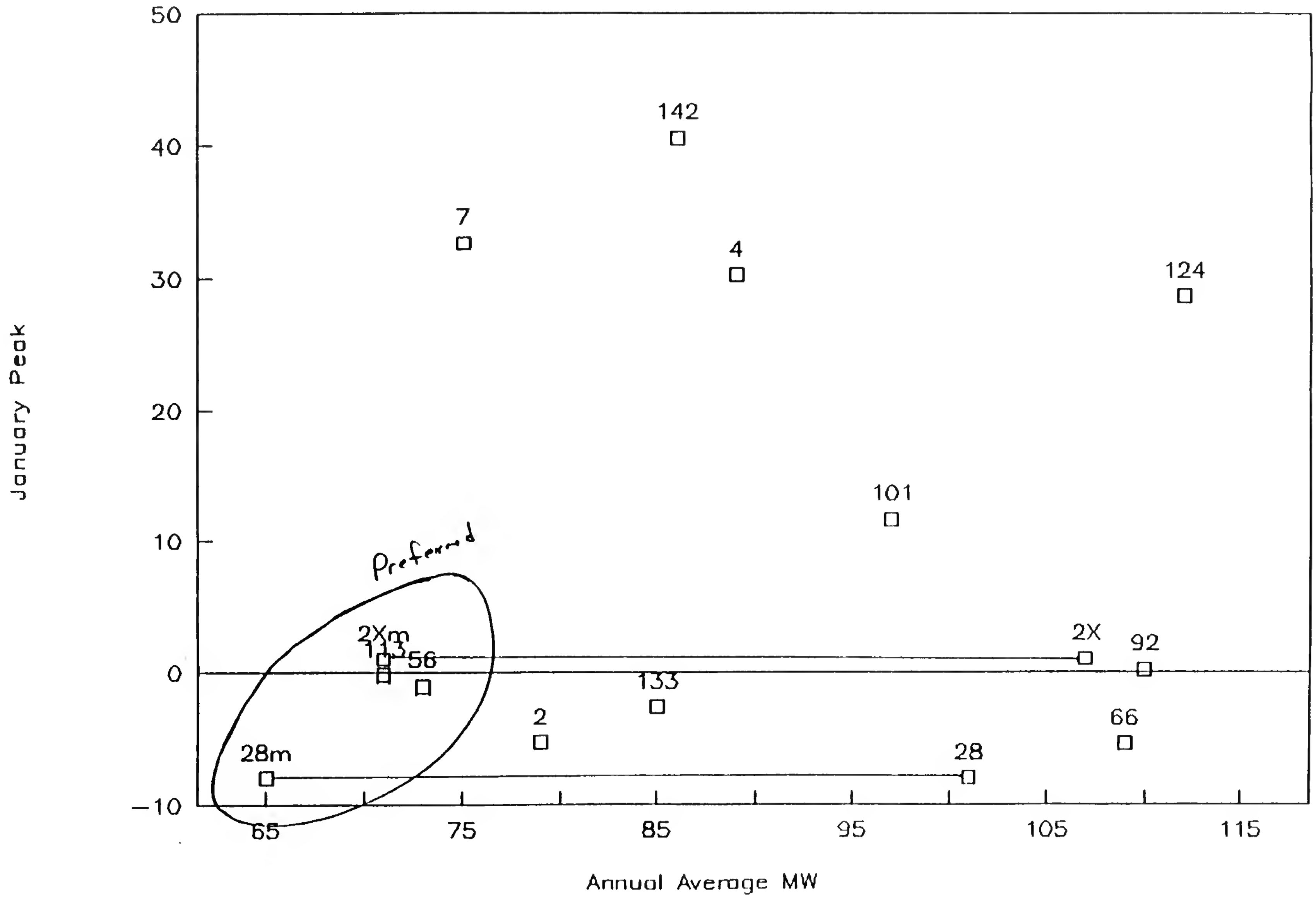
GRAPH # PC5 Incremental Revenue Requirement (TF & Ryan)

Thompson Falls (TF) and Ryan (RY) are distributed through out all plans except the two lowest revenue requirement plans (2 & 2X).

GRAPH # PC6 Incremental Revenue Requirement (Bird)

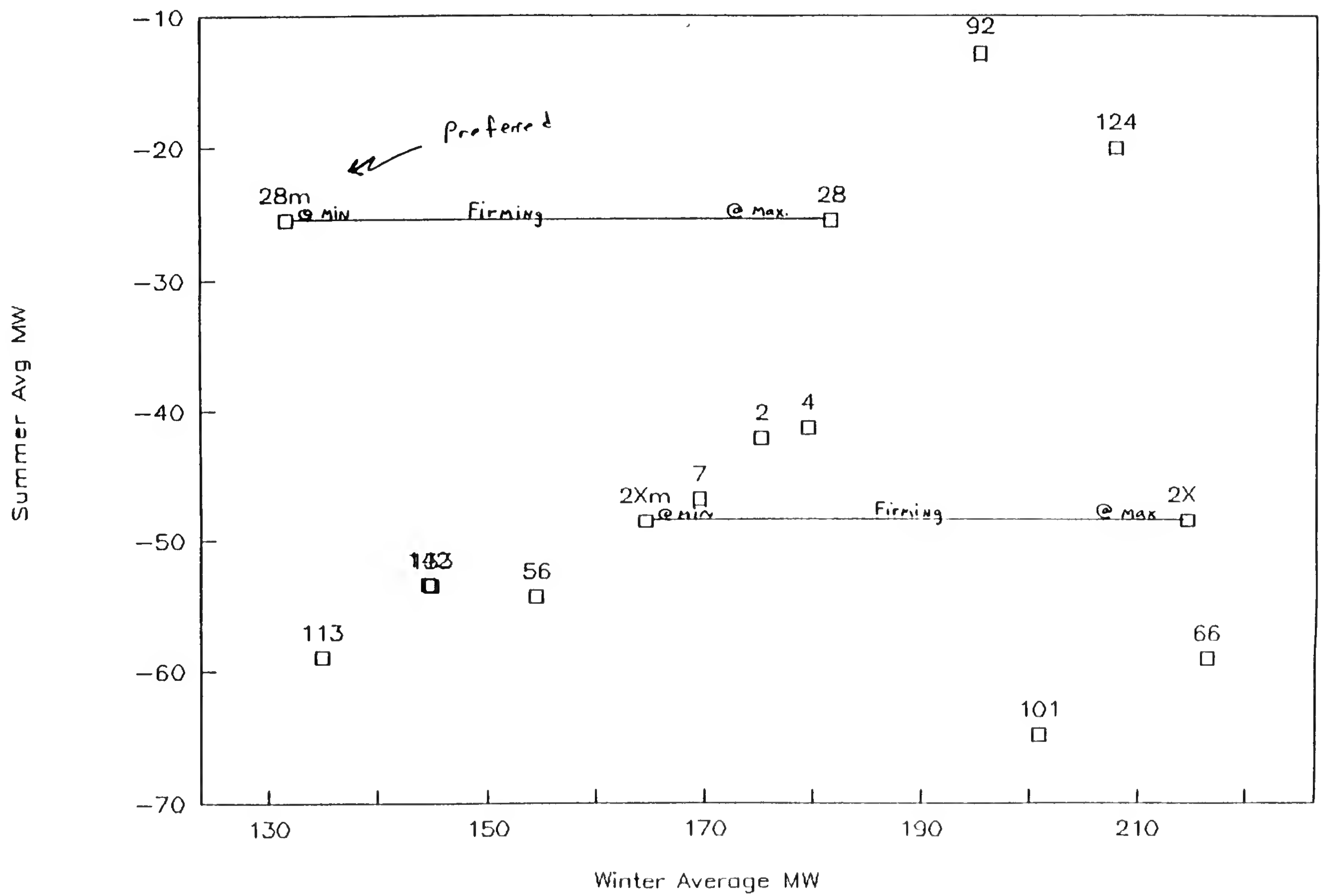
Bird, in some form, appears in most plans.

2000 Surplus & Deficiency



GRAPH SD1

2000 Surplus & Deficiency



GRAPH SD2

PLAN SURPLUS AND DEFICIENCY, 2000

GRAPH # SD1 Annual Energy and January Peak

Plan 28 provides energy resource flexibility and is the plan which leaves the bid window (1995 - 2000) with the least amount of energy and peak surplus. Plan 142 has the maximum peak surplus (40 MW) and Plan 124 has the maximum energy (113 aMW).

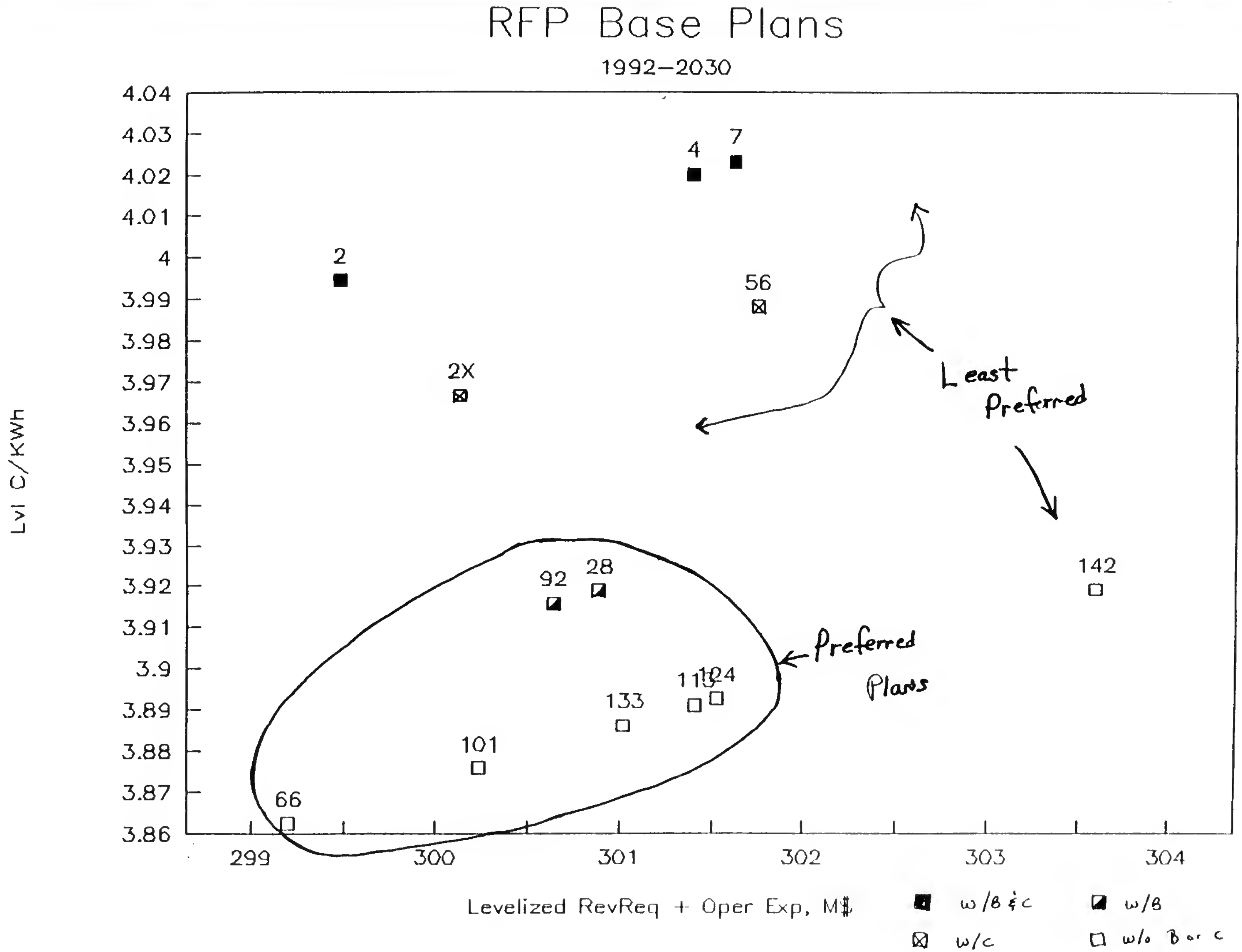
GRAPH # SD2 Winter & Summer Energy

Plan 28 provides the best flexibility with respect to energy surplus. Plan 92 comes closest to energy balance in the summer months because of LS re-powering of the Bird Plant.

NOTE:

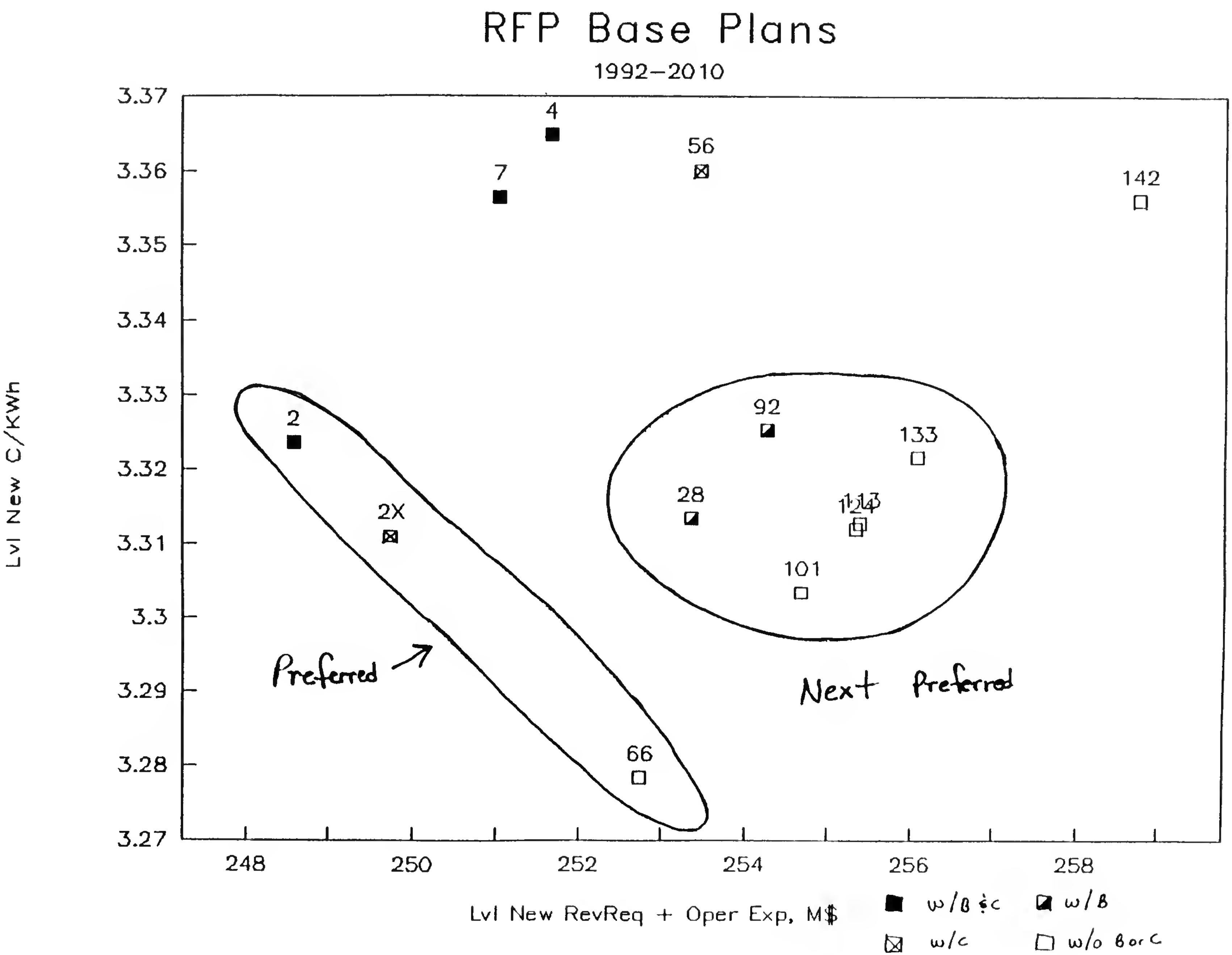
(1) MPC's peak load forecast is completed using average peak day temperature conditions. If a severe cold front moves through the entire state it is possible for the actual peak to exceed the forecast by 100 MW or more.

(2) It is assumed that MPC's ICP reserve obligation in 2000 is approximately 200 MW. The surplus and deficiency numbers take the reserve obligation into account.

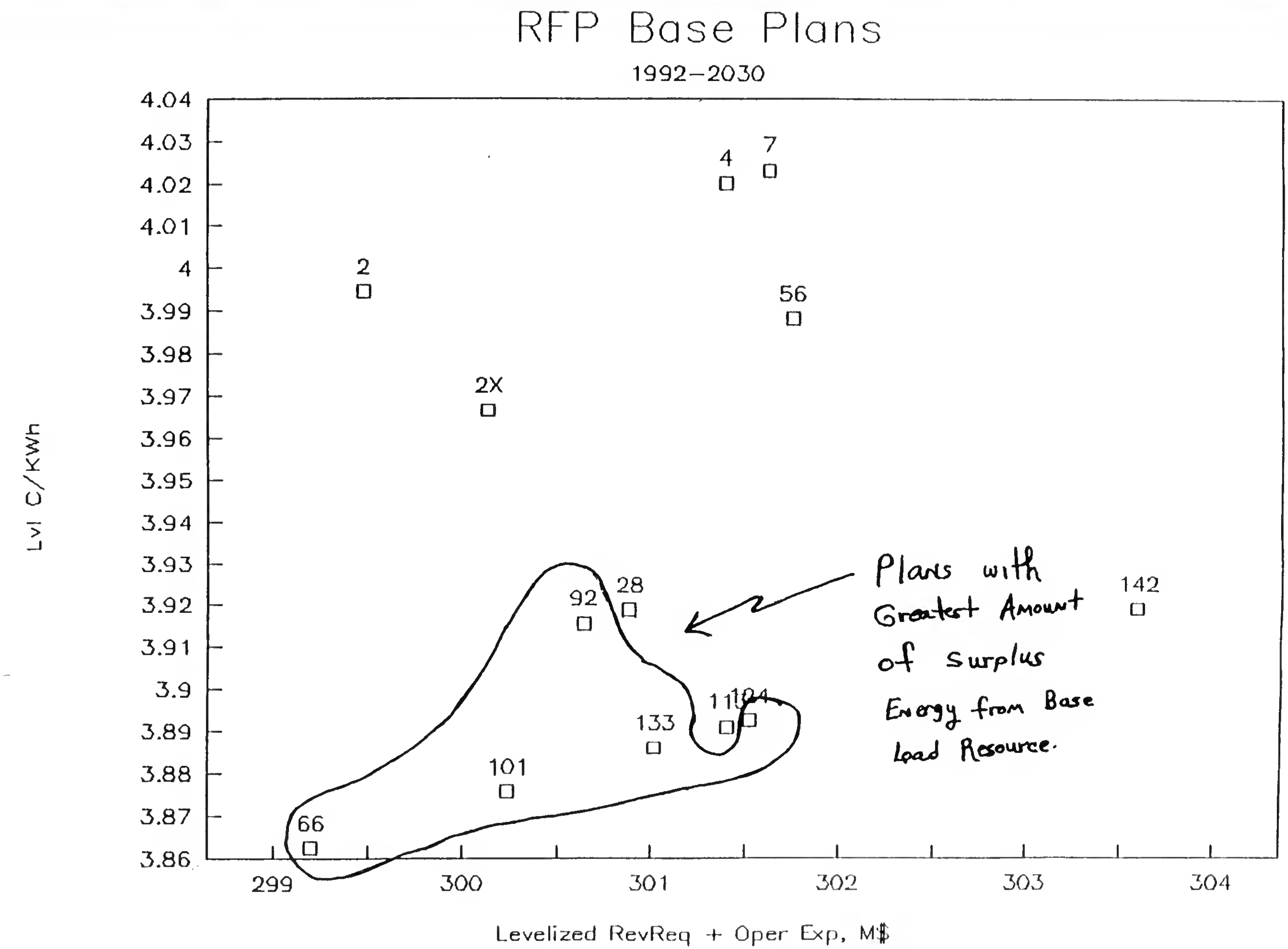


RFP Base Plans
1992–2030
Lvl C/KWh
4.04
4.03
4.02
4.01
4
3.99
3.98
3.97
3.96
3.95
3.94
3.93
3.92
3.91
3.9
3.89
3.88
3.87
3.86
299
300
301
302
303
304
Levelized RevReq + Oper Exp, M$
2
2X
4
7
56
92
28
66
101
133
113
124
142
Least Preferred
Preferred Plans
w/B & C
w/B
w/C
w/o B or C

GRAPH CC1


RFP Base Plans
1992–2010
Lvl New C/KWh
Lvl New RevReq + Oper Exp, M$
3.37
3.36
3.35
3.34
3.33
3.32
3.31
3.3
3.29
3.28
3.27
248
250
252
254
256
258
4
7
56
142
2
2X
92
133
28
113
124
101
66
Preferred
Next Preferred
w/B & C
w/B
w/C
w/o B or C

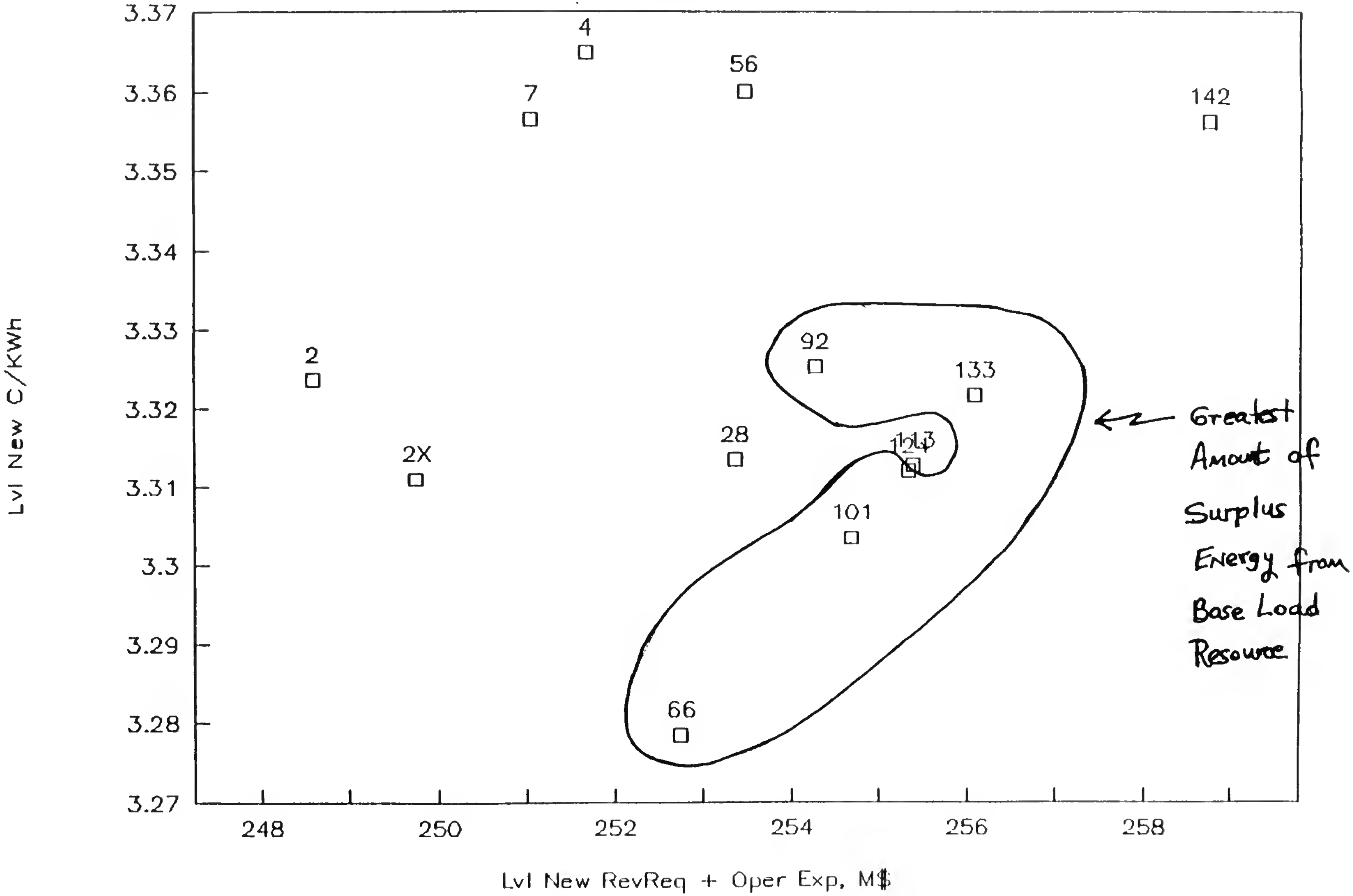
GRAPH CC2


RFP Base Plans
1992–2030
Lvl C/KWh
4.04
4.03
4.02
4.01
4
3.99
3.98
3.97
3.96
3.95
3.94
3.93
3.92
3.91
3.9
3.89
3.88
3.87
3.86
299
300
301
302
303
304
Levelized RevReq + Oper Exp, M$
2
2X
4
7
56
92
28
133
101
66
142
Plans with Greatest Amount of surplus Energy from Base load Resource.

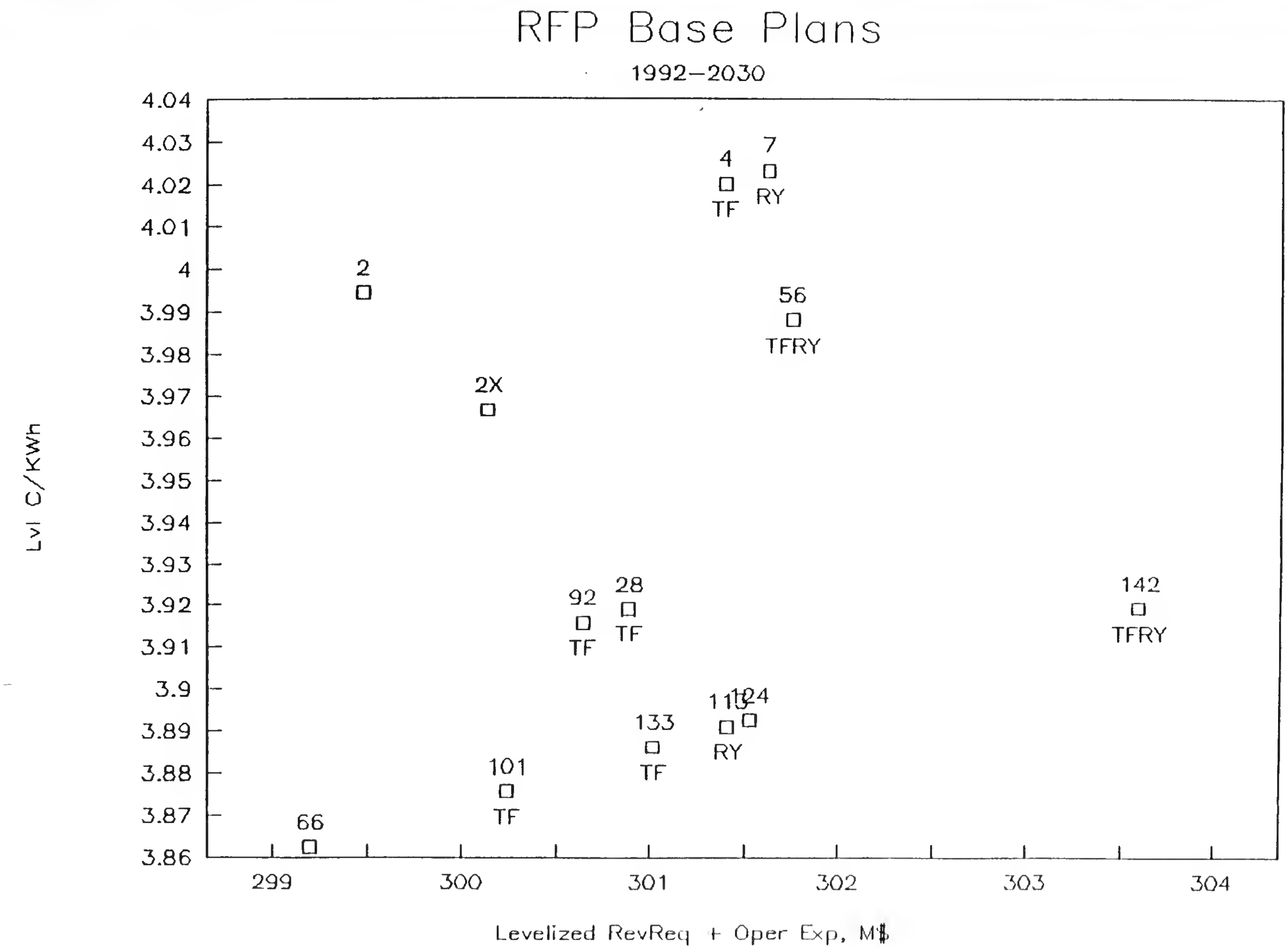
GRAPH CC3

RFP Base Plans

1992–2010



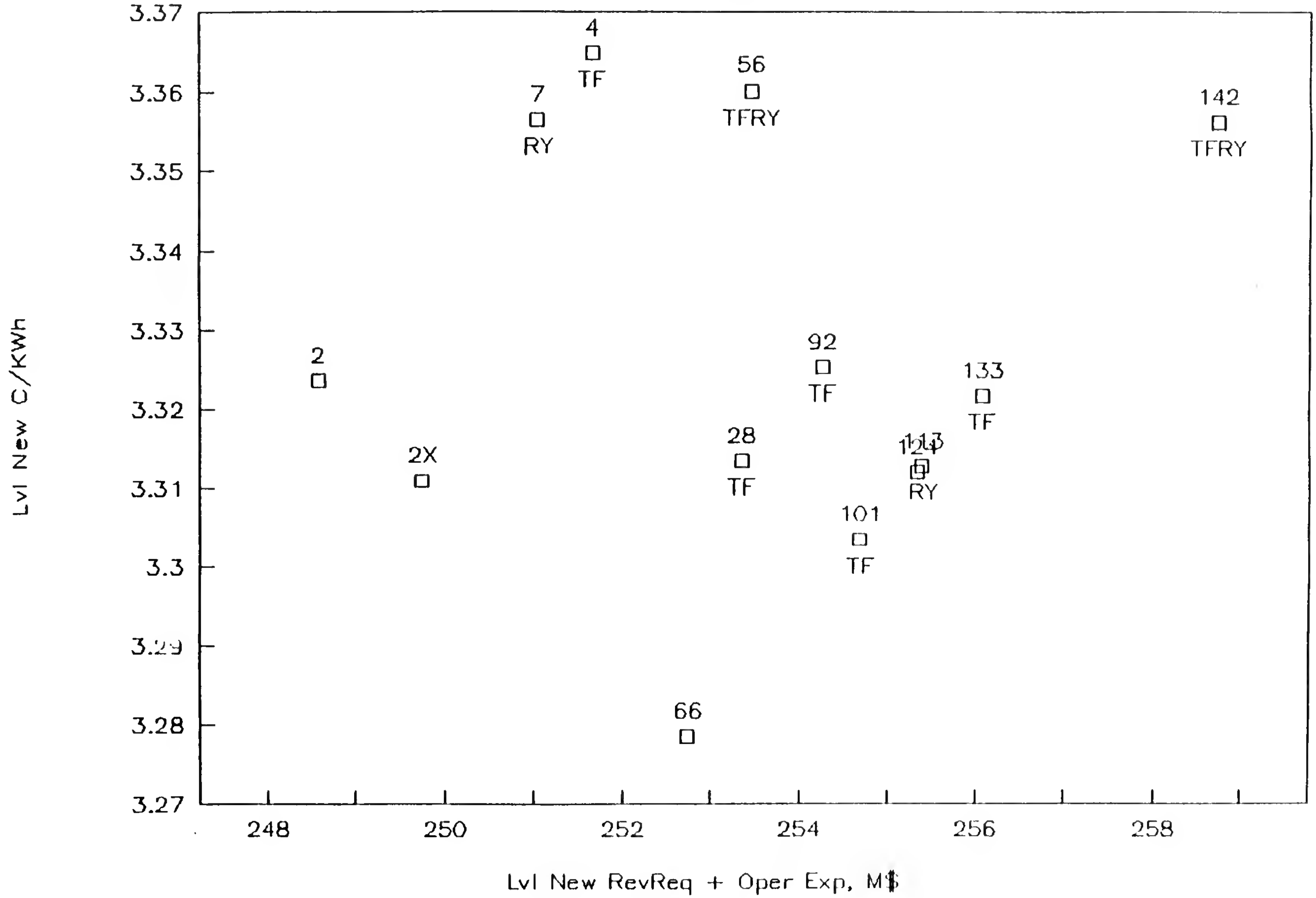
GRAPH CC4


RFP Base Plans
1992–2030
Lvl C/KWh
4.04
4.03
4.02
4.01
4
3.99
3.98
3.97
3.96
3.95
3.94
3.93
3.92
3.91
3.9
3.89
3.88
3.87
3.86
299
300
301
302
303
304
4
TF
7
RY
2
56
TFRY
2X
92
TF
28
TF
142
TFRY
133
TF
124
RY
101
TF
66
Levelized RevReq + Oper Exp, M$

GRAPH CC5

RFP Base Plans

1992–2010



GRAPH CC6

OBSERVATIONS CUSTOMER CONCERNS

GRAPH # CC1 Levelized Revenue Requirements and Operating Expenses vs. Levelized Cents per kwh.

1992 - 2030: Plans without Stone have about the same incremental revenue requirements but have higher rates. Note plans 92 and 28 have Stone B and are relatively close (within $0.003/kwh) to plans without Stone.

GRAPH # CC2 Levelized New Revenue Requirements and Operating Expenses vs. Levelized New Cents per kwh.

1992 - 2010: Plans 2, 2X, and 66 appear to be best plans which minimize both rates and revenue requirements. Plans 2, 2X, 4, 7, and 56 appear to be least desired. Plans 28, 92, 101, 124, 113, and 133 appear to be next best. Plans 4, 7, 56 and 142 appear to be least desired.

GRAPH # CC3 Levelized Revenue Requirements and Operating Expenses vs. Levelized Cents per kwh.

1992 - 2030: Plans with the greatest amount of surplus appear to be best but are dependent upon off system revenues. Note Plan's 28 and 113 position with respect to plans with the greatest amount of surplus.

GRAPH # CC4 Levelized New Revenue Requirement and Operating Expenses vs. Levelized New Cents per kwh.

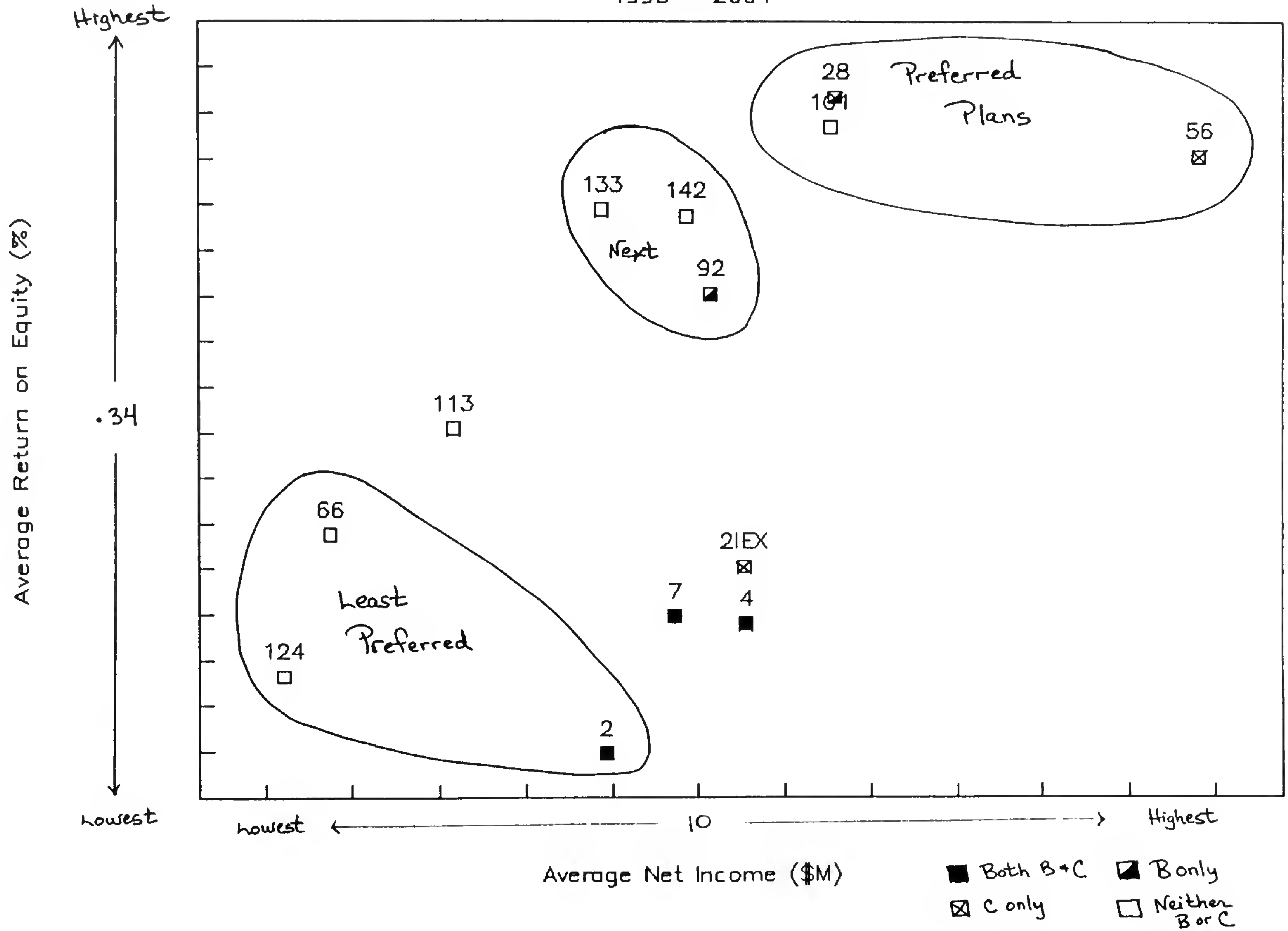
1992 - 2010: Plans with less amounts of surplus energy (2, 2X and 28) appear to fair well.

GRAPH # CC5 & CC6 Levelized Revenue Requirements and Operating Expenses, vs. Levelized Cents per kwh 1992 - 2030, and Levelized New Revenue Requirements and Operating Expenses vs Levelized New Cents per kwh 1992 - 2010.

Thompson Falls appears most in the preferred plans where as Ryan appears once. The combination of both Thompson Falls and Ryan appears least preferred over including just one in the plan.

RFP Base Plans

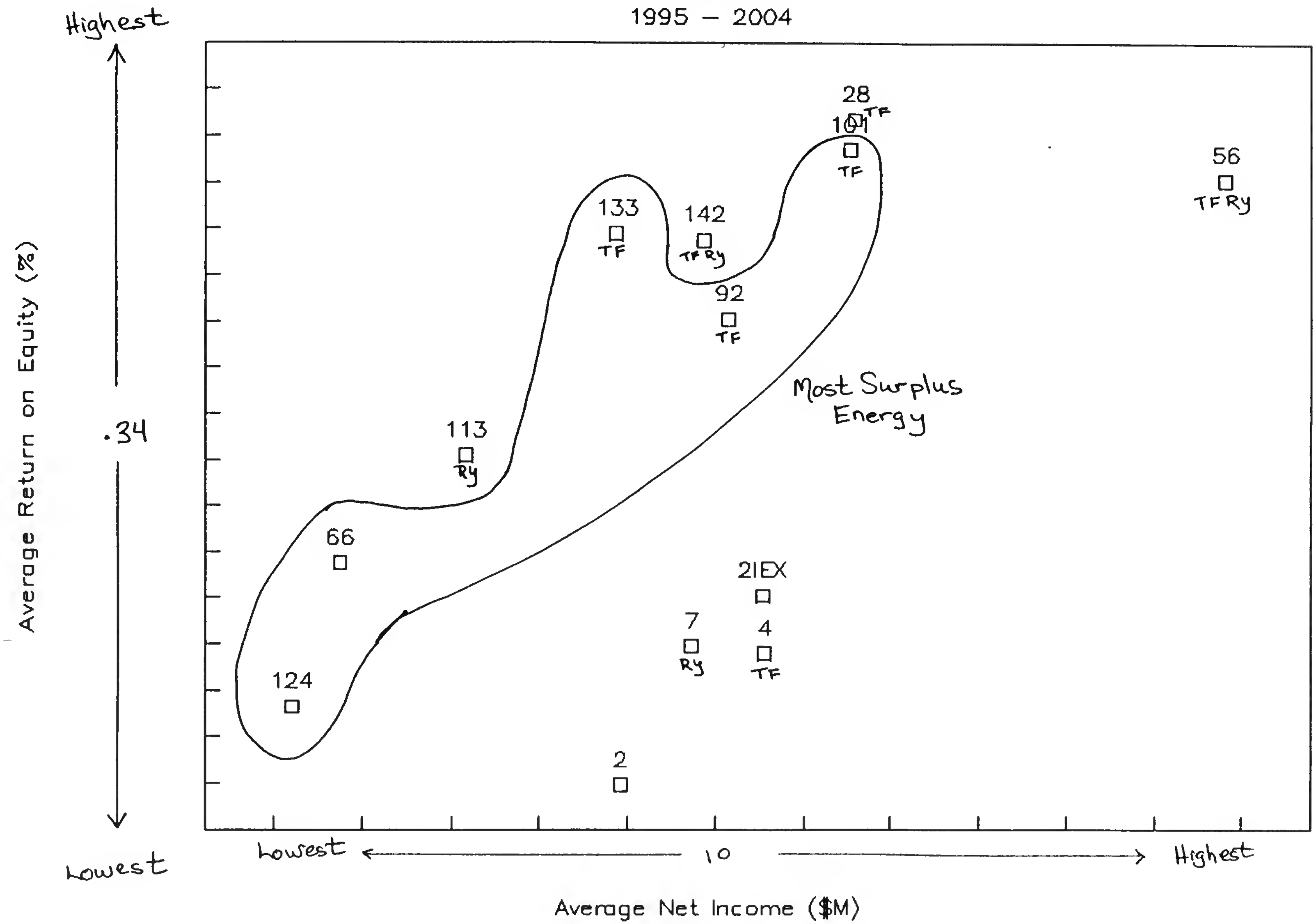
1995 – 2004



GRAPH OCI

RFP Base Plans

1995 – 2004



GRAPH OC2

OWNER CONCERNS

GRAPH # OC1 Average Net Income vs. Average Return on Equity

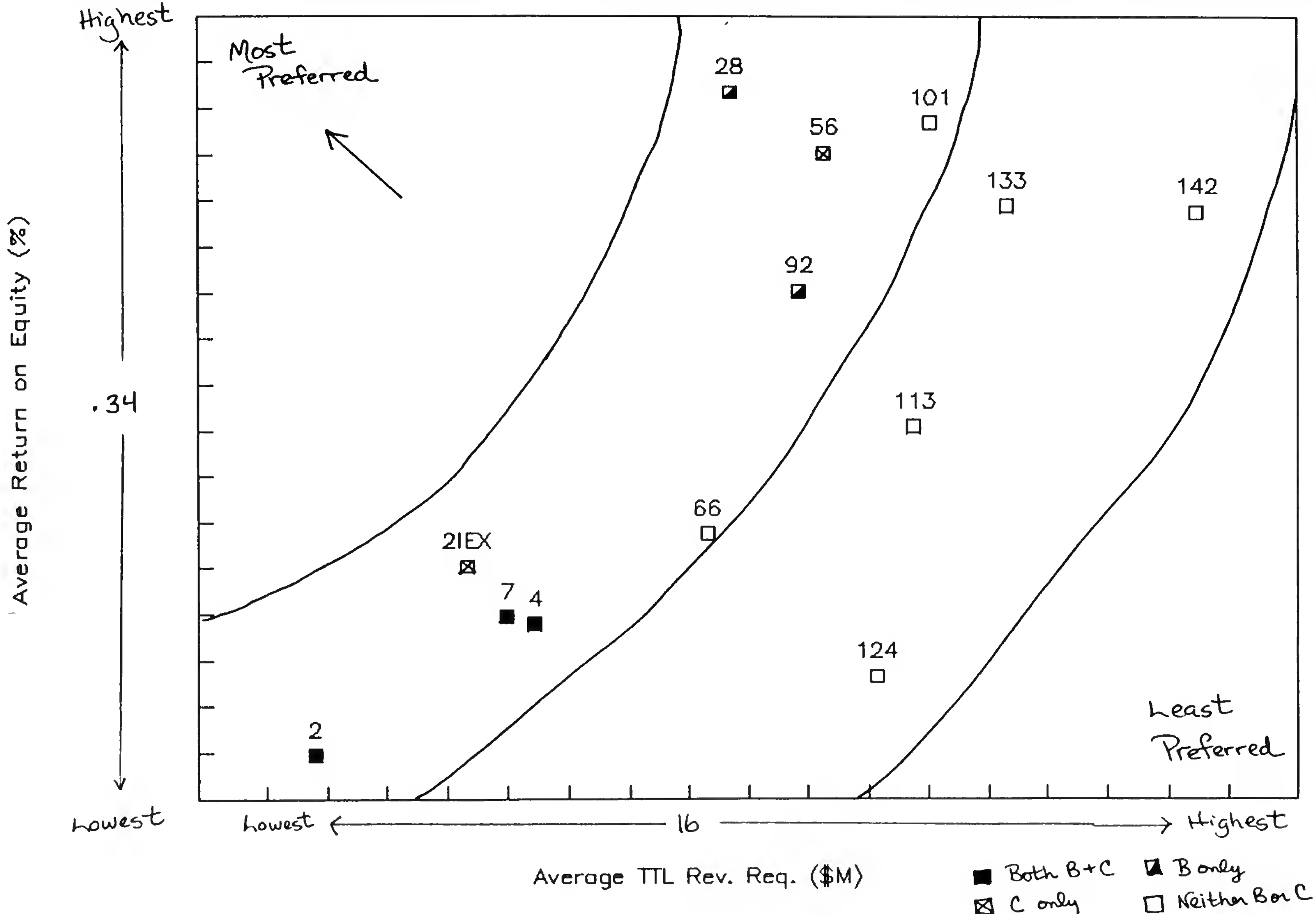
1995 - 2004: Plans 56, 28, and 101 are preferred. Plans with both Stone B and C are not as preferred as plans with no Stone or just one Stone resource.

GRAPH # OC2 Average Net Income vs. Average Return on Equity

1995 - 2004: Plans with Thompson Falls or both Thompson Falls and Ryan appear to perform the best. Plans 28 and 56 have less surplus energy and the best plans which maximize both return on equity and net income.

RFP Base Plans

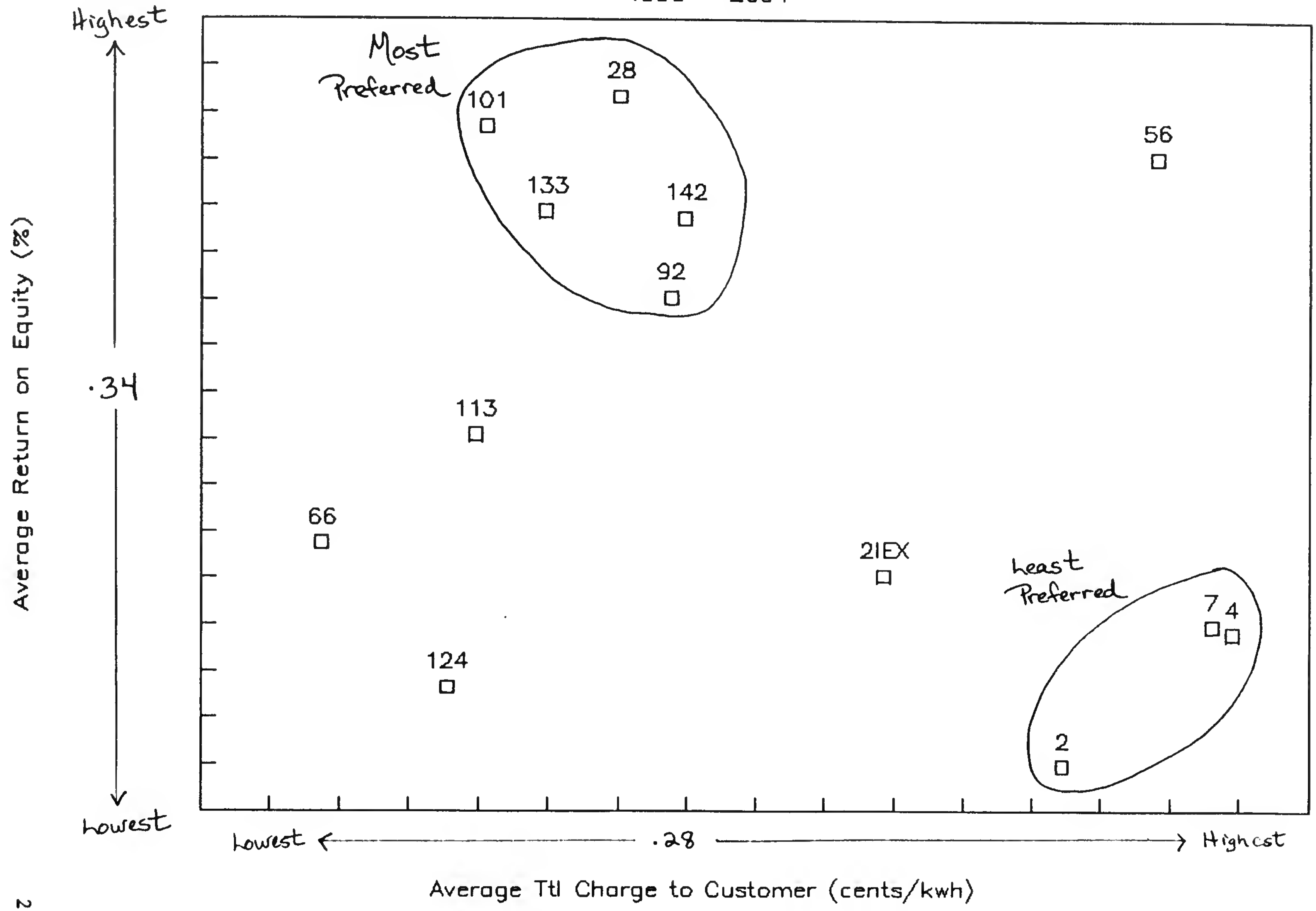
1995 – 2004



GRAPH C01

RFP Base Plans

1995 – 2004



GRAPH CO2

CUSTOMER AND OWNER CONCERNS

GRAPH # CO1 Average Total Revenue Requirements vs Average Return on Equity 1995 - 2004

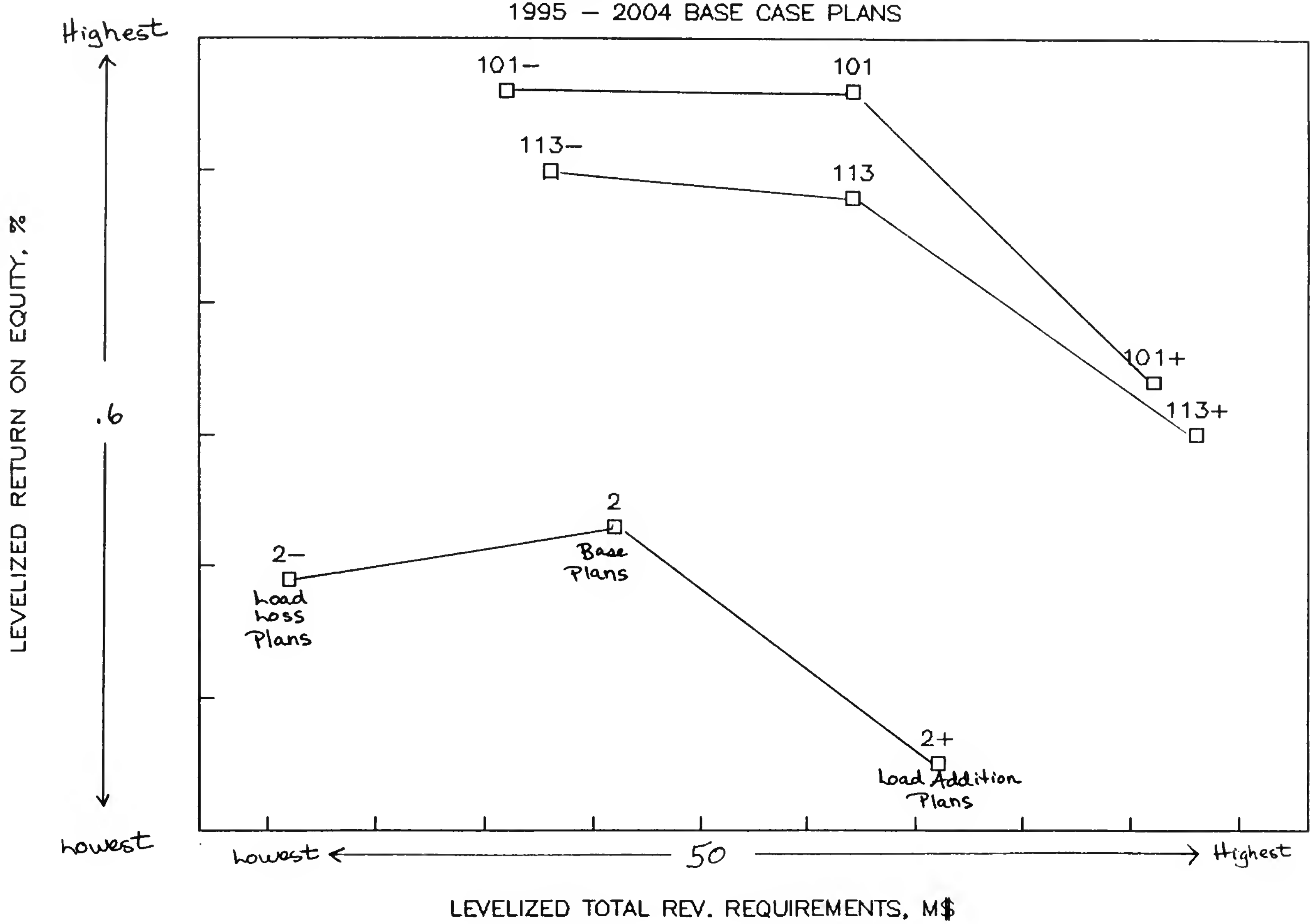
Several plans fall within a band which are the most preferred plans. These plans are 28, 56, 101, 92, 2X, 7, 4, 2. The key element in this graph is whether maximizing return on equity or minimizing revenue requirements are equally important.

GRAPH # CO2 Average Total Charge to Customer vs. Average Return on Equity 1995 - 2000

The preferred plans assume maximizing return on equity and minimizing rates. The preferred plans are 101, 28, 133, 142, and 92.

LOAD RISK & UNCERTAINTY

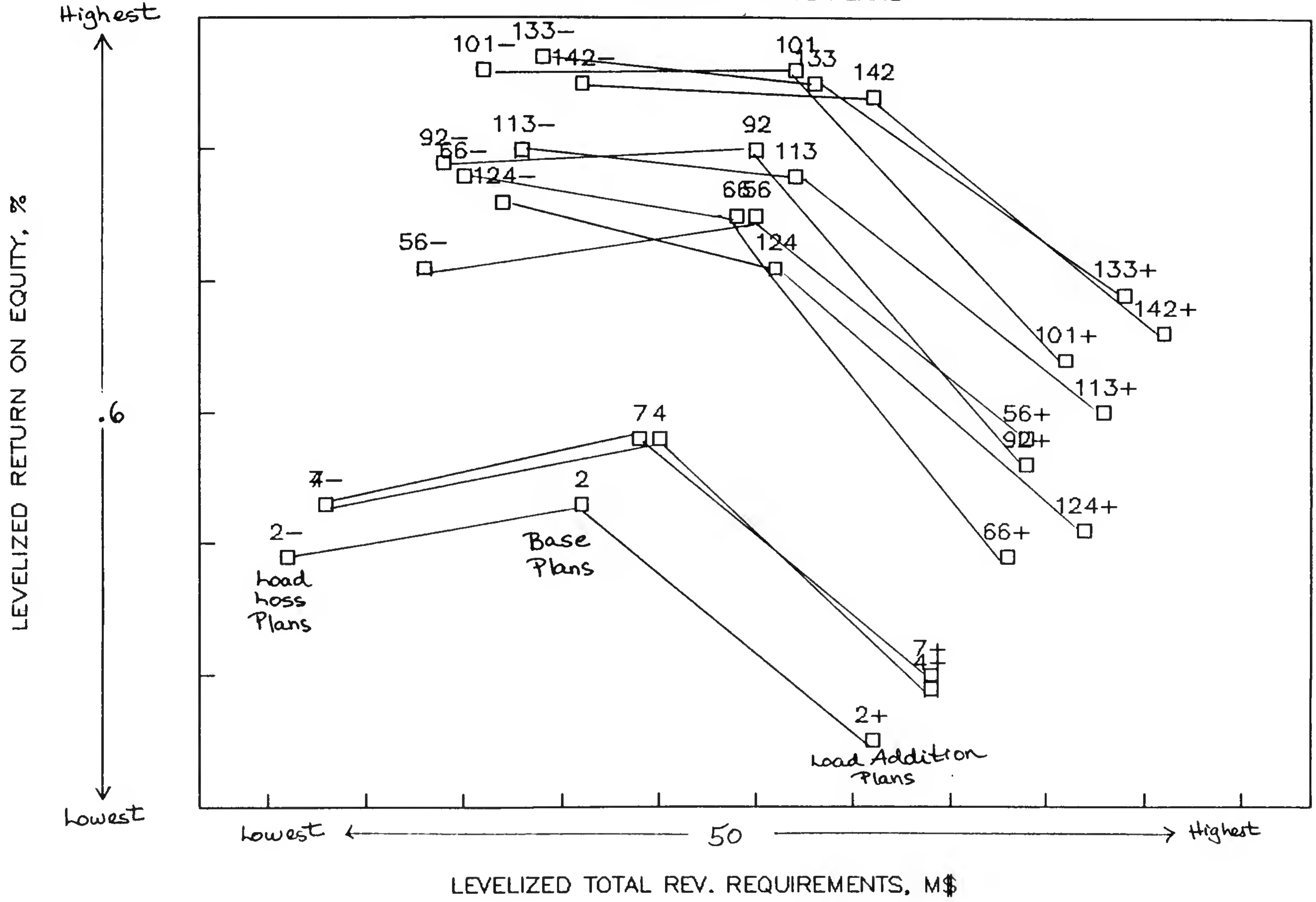
1995 – 2004 BASE CASE PLANS



GRAPH LRU1

LOAD RISK & UNCERTAINTY

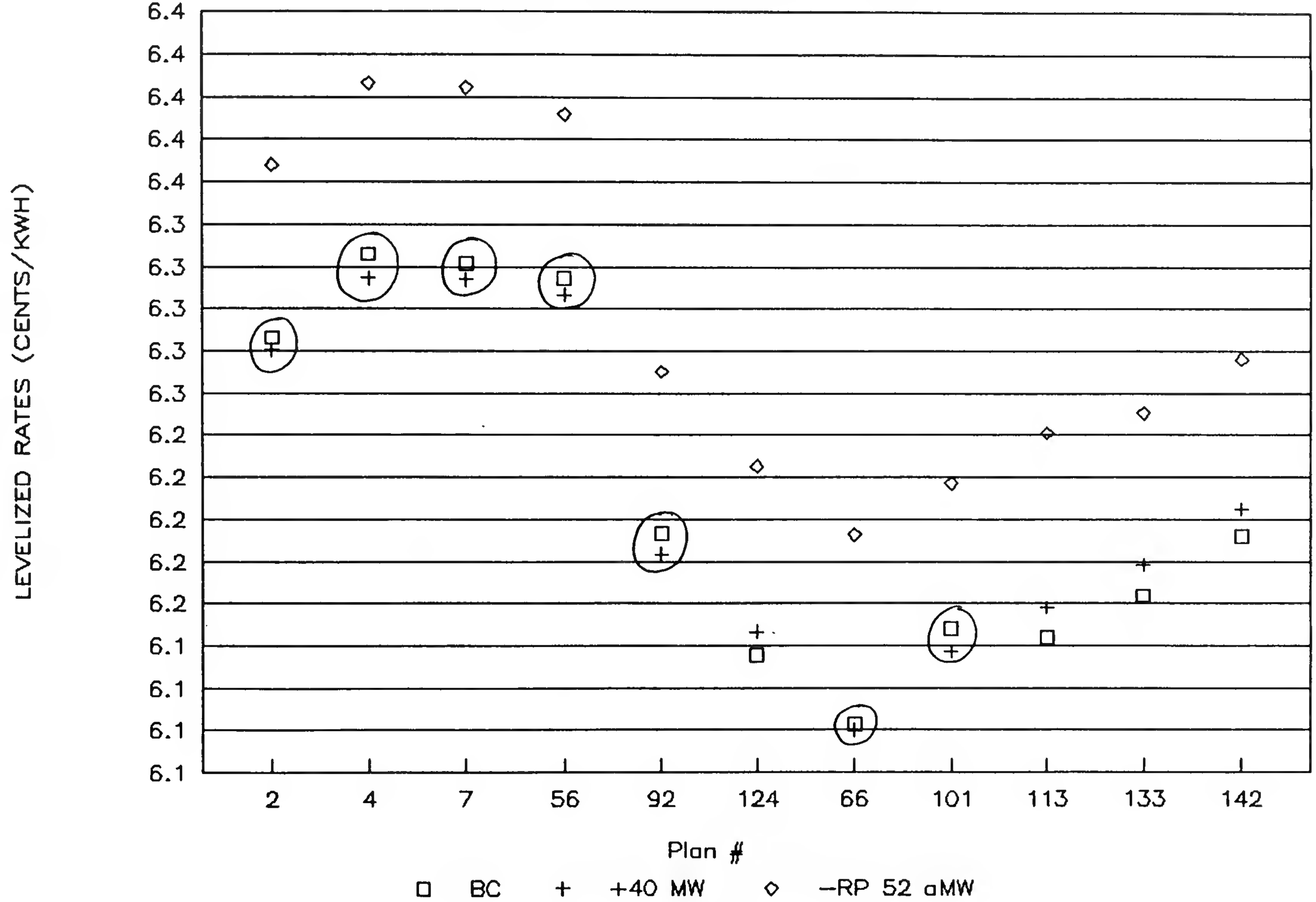
1995 – 2004 BASE CASE PLANS



GRAPH LRU1a

LOAD RISK & UNCERTAINTY

1995 – 2004 RFP BASE CASE PLANS



GRAPH LRU2

LOAD RISK AND UNCERTAINTY

GRAPH # LRU1 Loss or Addition of Load

Addition or Loss of Large Load: Assumes no re-timing of resources which is probably the most pessimistic scenario.

Addition of load: The magnitude of impact to all plans are about the same; revenue requirements increase and return on equity decreases. If MPC were able to re-time resources (discussed later) or acquire a lower cost resource to serve this load, then the impact would likely be less severe.

Loss of Load: Magnitude of revenue requirement for all plans are the same. Return on equity appears to decrease slightly in plans which include Stone while plans without Stone remain the same or slightly increased. The return on equity difference is probably due to the ability to sell the surplus from the non Stone plans (ie. include Westmoreland) year around. Re-timing of resources may cause an improvement in the return on equity. The loss of a different type of large load, such as a high load factor load, would reduce the need for peak resource. The ability to re-time or option "out" a resource would be important if the surplus couldn't be packaged and sold off system at a reasonable price. Call back provisions in any sale could be important. Plans 133, 101, 142, 113, 66, and 124 preferred under those conditions.

GRAPH # LRU2 Rates

The addition of a large load has little impact on rates given the assumption for acquired energy. The loss of a large load (RP Chem) would have a significant impact on rates. Rates increase to cover the same resource costs. MPC is surplus on energy and deficient on capacity.

<u>General Comments - Non Quantifiable</u>

* The exposure to a large increase or decrease in load would only be a problem until the future (and existing) resource stack can be adjusted to accommodate the change.

* Most of the resource plans are not significantly peak resource surplus by 2000. These plans generally just meet the need for peak resource which means MPC will need to acquire peak resource shortly after 2000.

* Load uncertainty can be addressed in the following ways:

  a. Option "in" a resource to come on quickly if the growth should increase.
  b. If a resource is planned, maintain the flexibility to option "out" a resource to a later on line date.

  c. Demand side resource acquisition could be increased or decreased to meet unexpected <u>long</u> term changes.

* The Pacific Northwest firm market may not be available to the same extent in the future as in the past because of:

  a. Load growth using existing surplus

  b. Changing hydro conditions

  c. Existing plant closure

  d. Conservation, if acquired to off set load growth, will not create additional surplus.

* Open electric transmission access could expose the utility to surplus generation if existing load options for another supply. This would suggest a conservative approach to surplus generation if transmission limitation exists to transport surplus power to market or if the surplus generation is not competitive.

* Markets to acquire firm resource from the east (Basin) exists today. However, it is anticipated that this market will be reduced as the surplus is dedicated to future load.

* Last year's forecast used the following load growth probabilities:

Base Case Growth	55%
Low Case Growth	28%
High Case Growth	17%

This would suggest that plans that just meet the base case load forecast (rather than having surpluses) are probably best.

* On the other hand, demand side resource acquisition quantities are not fully understood at this time. It is possible that quantities acquired may be more or less than forecast.

Flexible Resource Discussion

* Plans that offer more resource flexibility in terms of responding to unanticipated changes in load are preferred to those plans that do not.

* The following table applies:

	As Bid Timing Flexibility
Ryan	Yes, limit by FERC through 2188 relicense
T Falls	No, at timing limit already
Bird	Yes, MPC with preservation or LS Power
IPC 50MW	No, extend current contract
IPC 76MW	Yes, could start in 1996 instead of 1998
Stone B	No
Stone C	No
Basin	Some
Tiber	Yes, on-line as late as 2003 possible
Westmoreland	No

* Bird is one of the most flexible resources available. Discussions with sponsors may reveal flexibility not currently understood.

* IPC 50 MW has the flexibility to increase to 76 MW and Westmoreland has proposed a Combustion Turbine option to their combined cycle bid.

* Plan Flexibility

	Bird	Ryan	Basin	Id50	ID76	Tiber	Total
2	X		X	X		X	4
4	X		X	X			3
133	X				X		2
7	X	X	X	X			4
113	X	X			X		3
56		X	X	X			3
142	X	X			X		3
66			X		X		2
124	X		X	X			3
92			X	X			2
101			X		X		2
28	X		X	X			3
2X	X		X		X		3

Plans that provide the most "built" in flexibility are 2 and 7. Plans 4, 113, 56, 142, 124, 28 and 2X also provide significant flexibility.

FUEL DISCUSSION

Fuel Discussion

* Basin - Antelope
  - Mine mouth coal
  - Price may be adjusted for operating costs and reserves
  - Commodity estimated to increase at fixed rate annually
  - Two sources of supply
    - < 3% from Dakota Coal Company (crushed coal)
    - > 97% from Dakota Gasification Co. (coal fines)
    - (Both sources obtain their coal from the same mine)

* LS Repowering of Bird
  - Petroleum coke from Conoco
  - Long term coke contract with anticipated renewal
  - Coal secondary fuel
  - Fixed fuel price bid

* Stone B
  - Steam pressure reducing
  - Steam created by existing hog fuel and natural gas system
  - No supply problems

* Stone C
  - Natural gas
  - Bids contain no specific fuel escalation
  - Fixed fuel price bid
  - Fuel source not defined but probably not a problem

* Westmoreland
  - Natural gas
  - Maximum fuel escalation at a cap with possible share-the-savings if escalation fixed
  - Fuel source not defined
  - Availability for long term stated to not be a concern

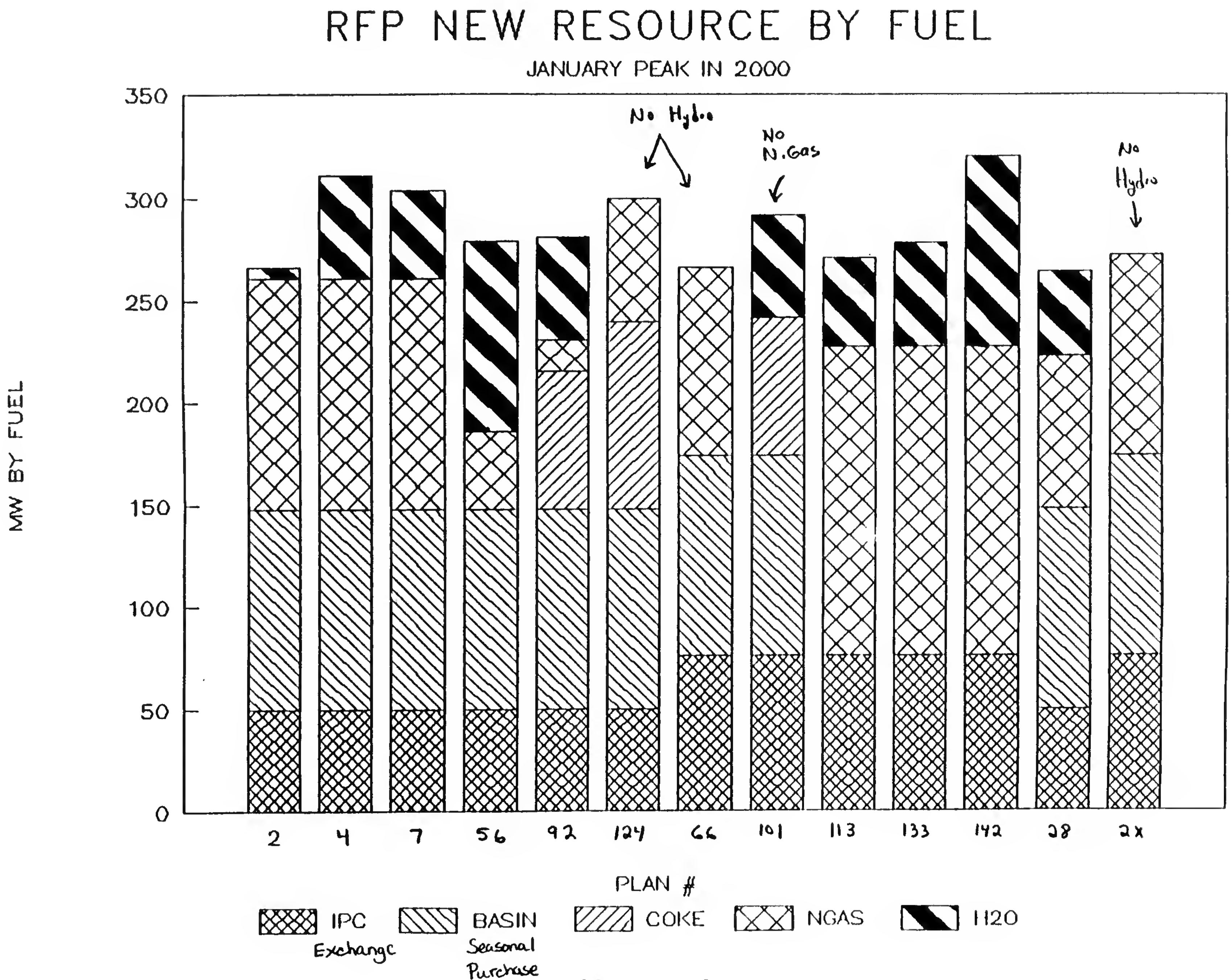
* Bird - MPC
  - Natural gas
  - Escalation at greater than inflation for these studies
  - Firm Transportation
  - Dry Creek storage
  - Source not defined

* Tiber
  - Water
  - Flows specified by Bureau of Reclamation for flood control, irrigation, and recreation
  - Have preliminary FERC permit

* Thompson Falls
  - Water
  - Have FERC permit

* Ryan
  Water
  Do not have FERC permit

* Idaho Power Co Exchange
  System resources, no fuel concerns



RFP NEW RESOURCE BY FUEL
JANUARY PEAK IN 2000
MW BY FUEL
350
300
250
200
150
100
50
0
No Hydro
No N.Gas
No Hydro
2
4
7
56
92
124
66
101
113
133
142
28
2x
PLAN #
IPC Exchange
BASIN Seasonal Purchase
COKE
NGAS
H2O

GRAPH FRU1

RISK AND UNCERTAINTY - *** FUEL SENSITIVITY ***

WESTMORELAND - fuel is natural gas

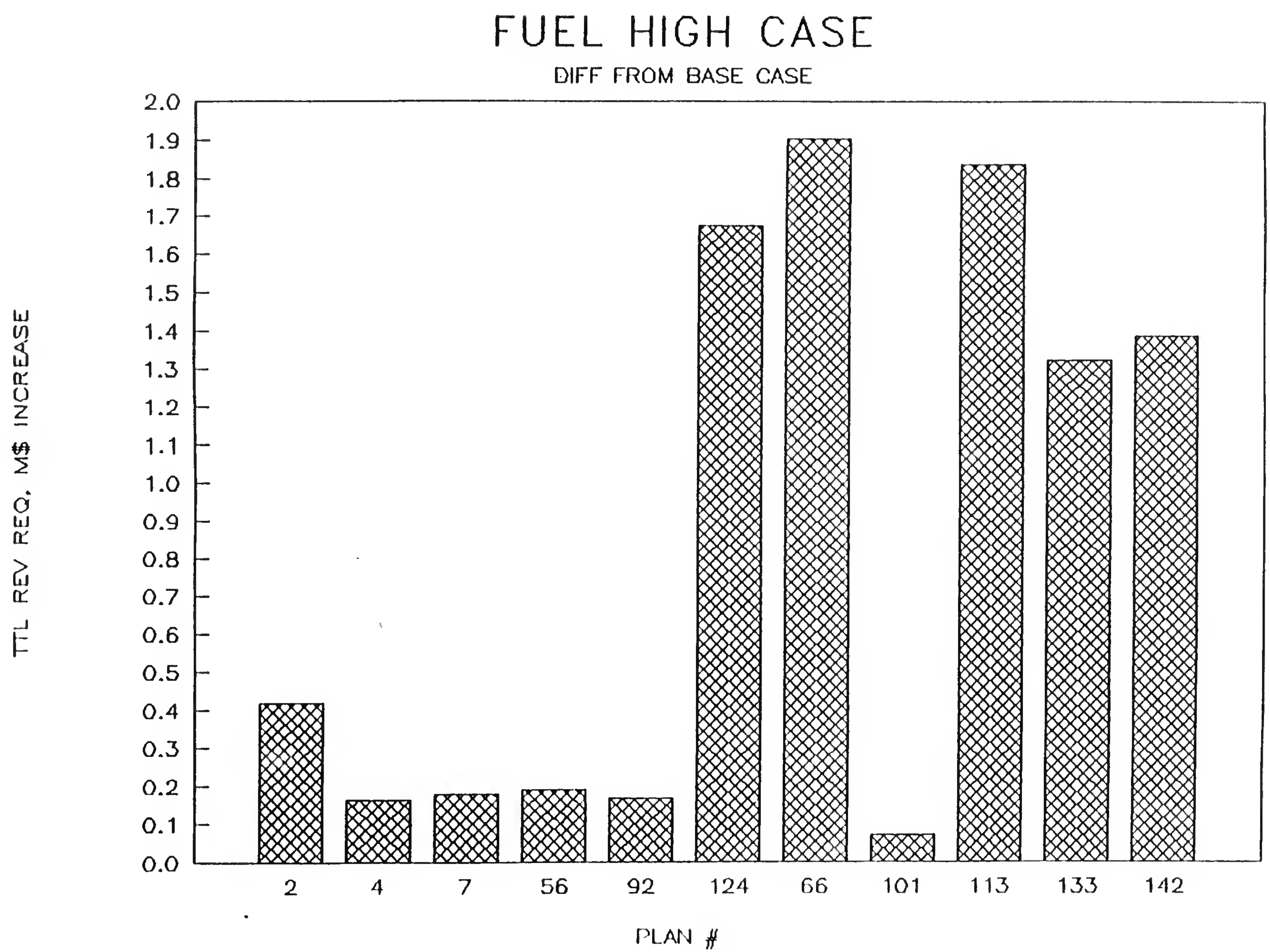
- Base Case - escalated at about the rate of inflation
- High Fuel - Escalated at 7%
- Low Fuel - escalated at 2%

BASIN - fuel is coal

- Base Case - escalated at below the rate of inflation
- High Fuel - escalated at 4.6%

BIRD PEAKING - fuel is natural gas

- Base Case - escalated at 7%
- High Fuel - escalated at 10%
- Low Fuel - escalated at 4%


FUEL HIGH CASE
DIFF FROM BASE CASE
TTL REV REQ, M$ INCREASE
2.0
1.9
1.8
1.7
1.6
1.5
1.4
1.3
1.2
1.1
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
2
4
7
56
92
124
66
101
113
133
142
PLAN #

GRAPH FRU2

Fuel Diversity

GRAPH # FRU1 RFP New Resources by Fuel

Generally, all plans provide some fuel diversity. Plans 113, 133, and 142 have the greatest reliance on natural gas resources. These same plans do not have the seasonal purchase from Basin. Plan 92 includes the most diverse set of resource fuel types. Plans 124, 66, and 2X do not include hydro resource. Plan 101 is the "No" natural gas plan. Plan 28 provides a good balance between hydro, exchange, seasonal purchase and fossil resources.

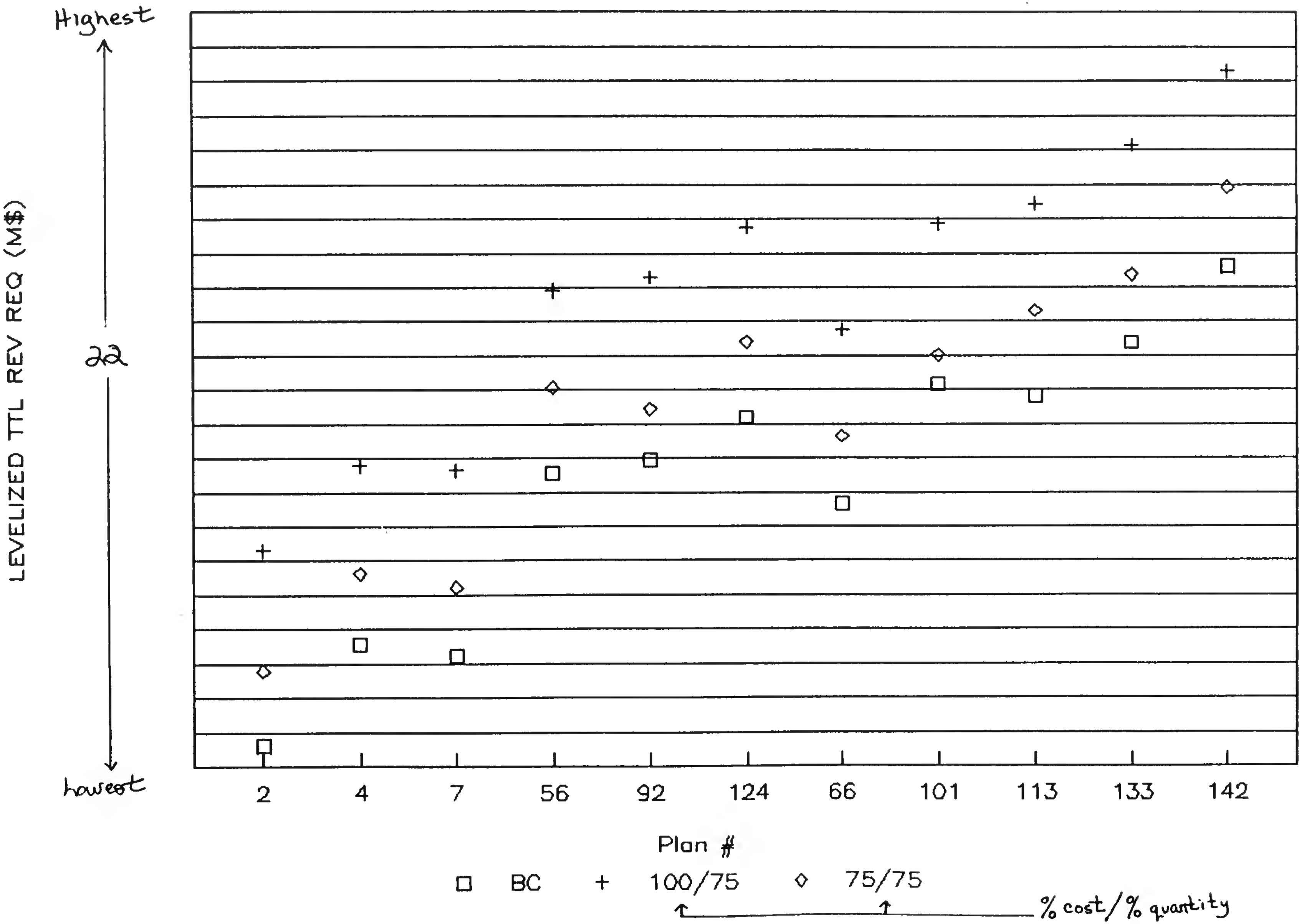
High Fuel Price Escalation

GRAPH # FRU2 High Fuel Case

Plans 124, 66, 113, 133 and 142 have the greatest exposure to high fuel cost. All of these plans include the Westmoreland combined cycle resource. <u>This exposure would be held by Westmoreland because they have placed a cap at about the rate of inflation on fuel escalation.</u> However, MPC may be faced with possible contract renegotiations or project failure if the high fuel scenario is correct.

DSM RISK & UNCERTAINTY

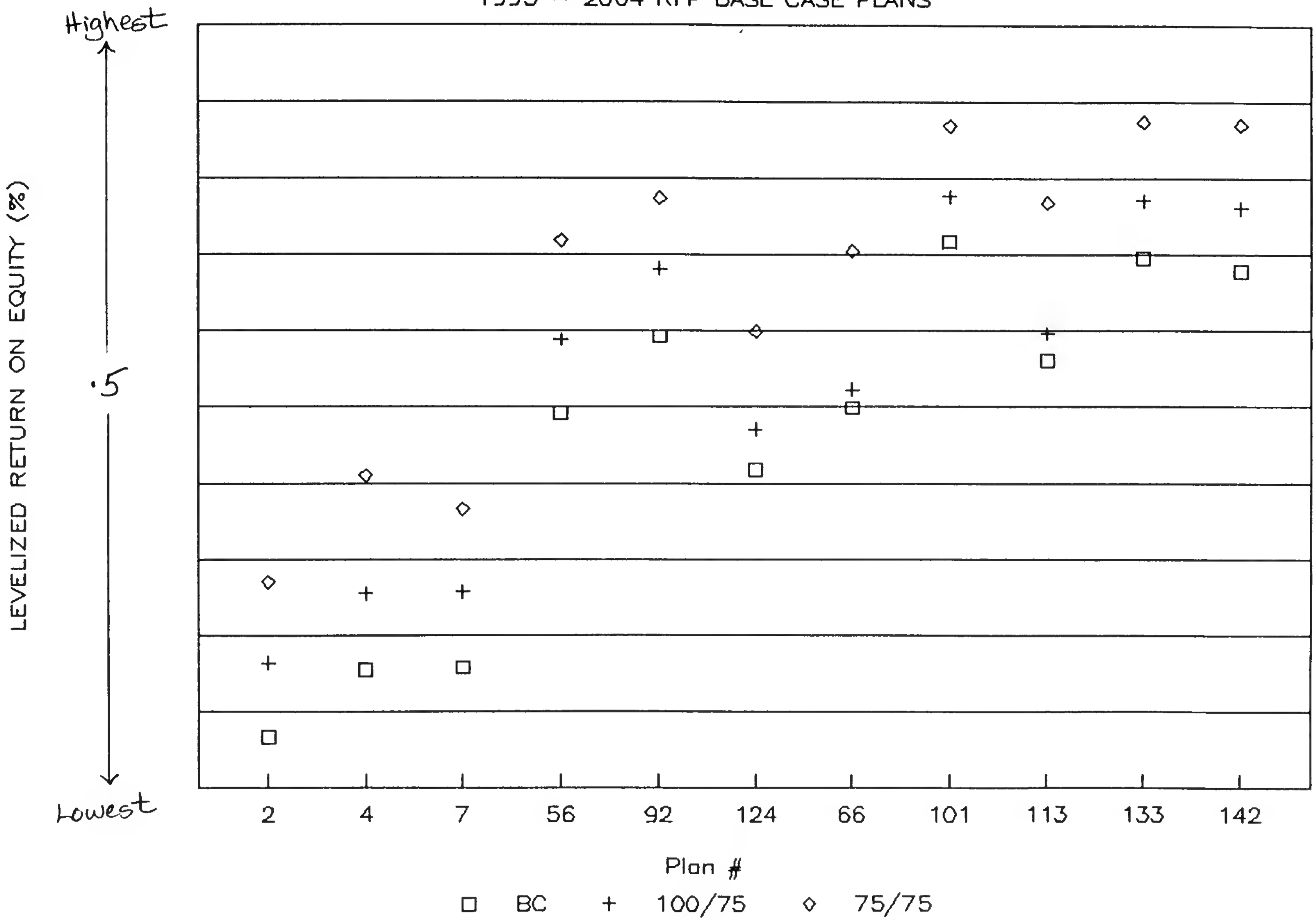
1995 – 2004 RFP BASE CASE PLANS



GRAPH DSMRU1

DSM RISK & UNCERTAINTY

1995 – 2004 RFP BASE CASE PLANS



GRAPH DSMRU2

DSM UNCERTAINTY

RESOURCE FLEXIBILITY

* IPC exchange, Stone B, Basin purchase and Bird appear most frequently in the three DSM optimized plans (SASA, SSSS, AAAA).

* Resource robustness: Resources which appear in the Base Case (SASA) resource plans and both the change case optimized plans (AAAA and SSSS) are considered the most robust; IPC exchange, Basin purchase, Bird.

* Plans that contain IPC exchange, Basin and Bird (ie. common in the above two statements) 2, 4, 7, 28, 124.

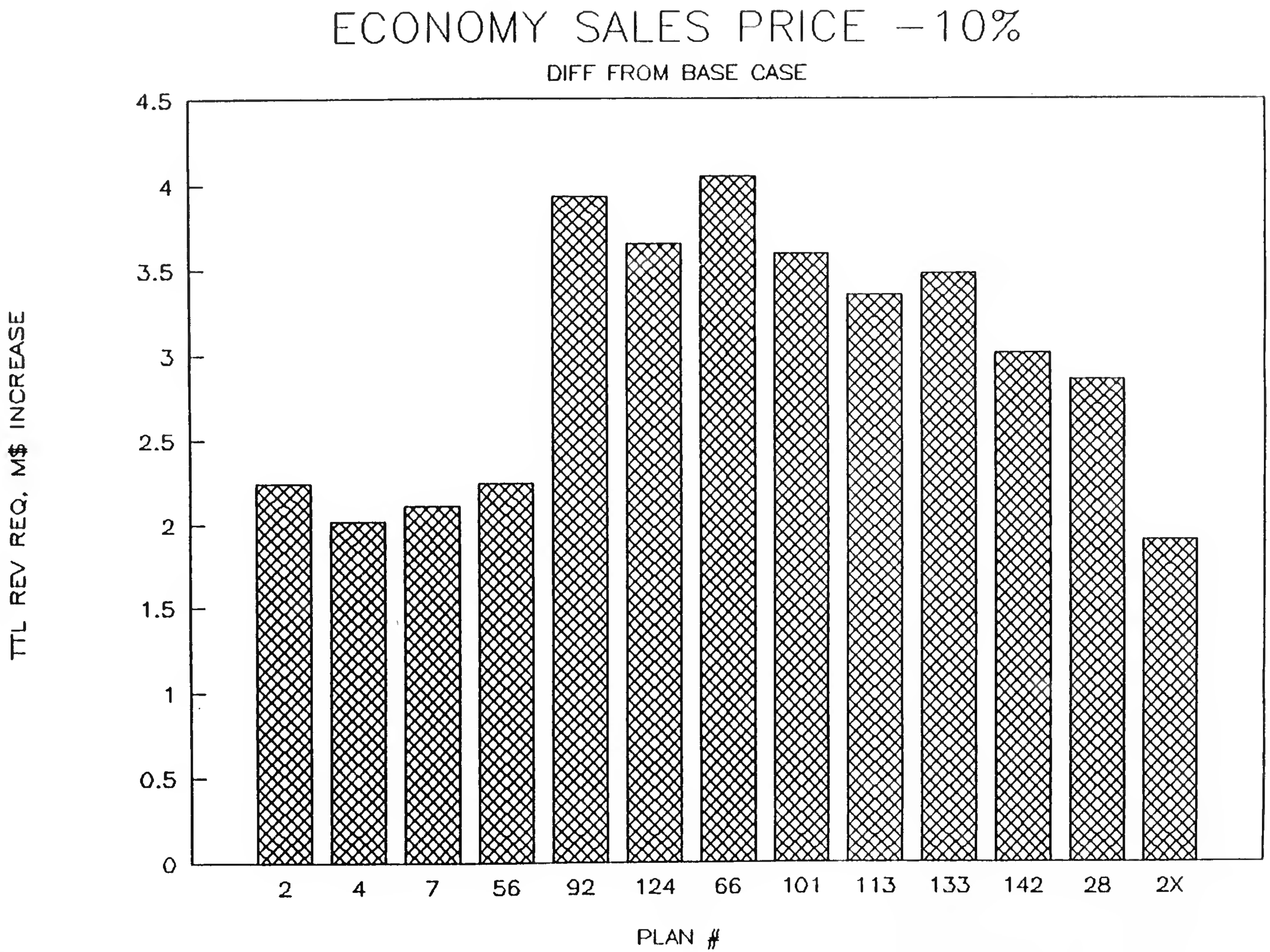
DSM UNCERTAINTY

GRAPH # DSMRU1 Levelized Total Revenue Requirements

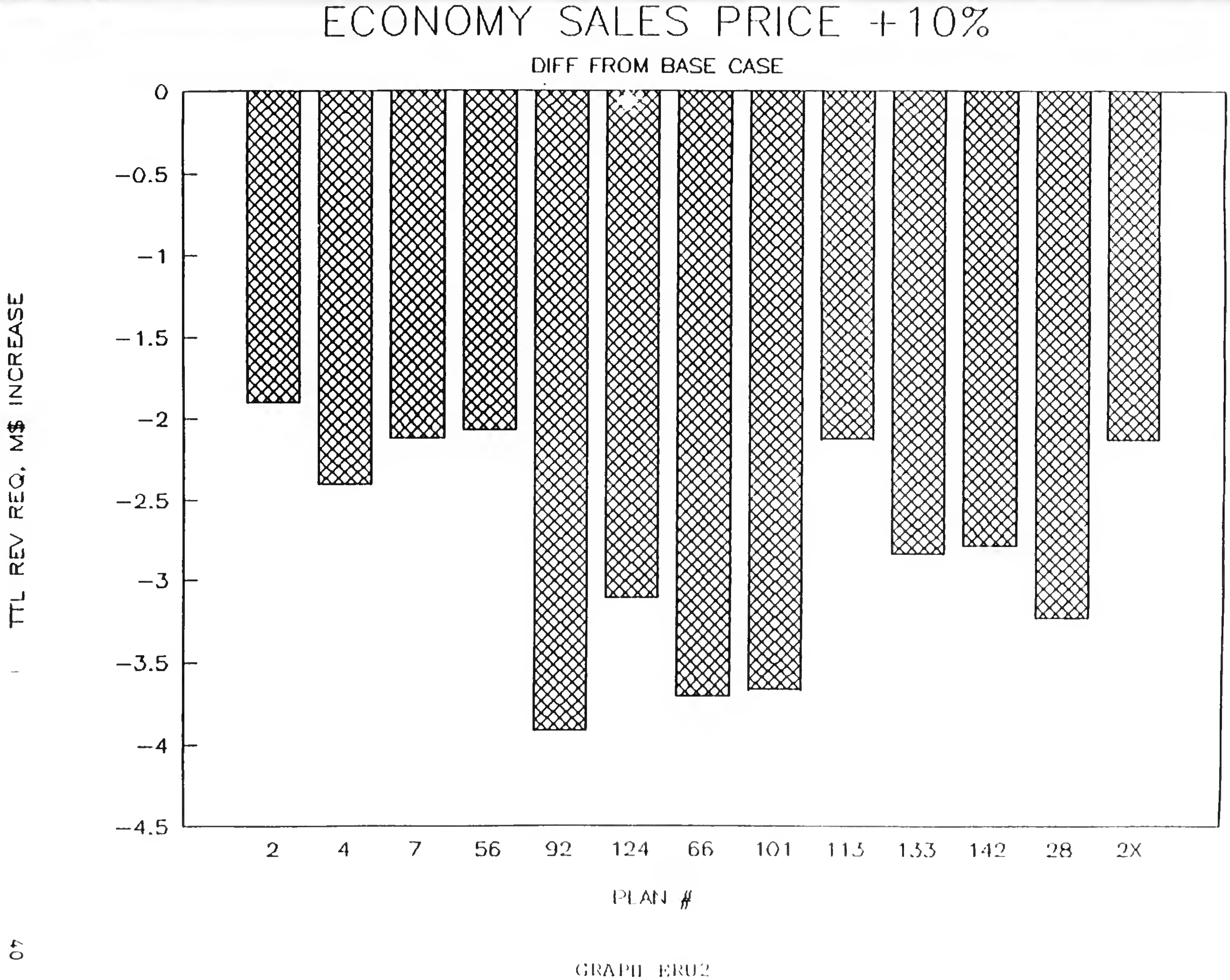
This graph shows, from the total revenue requirements perspective, that DSM investment provides the lowest cost plans. That is, moving away from the Base Case assumptions increase revenue requirements.

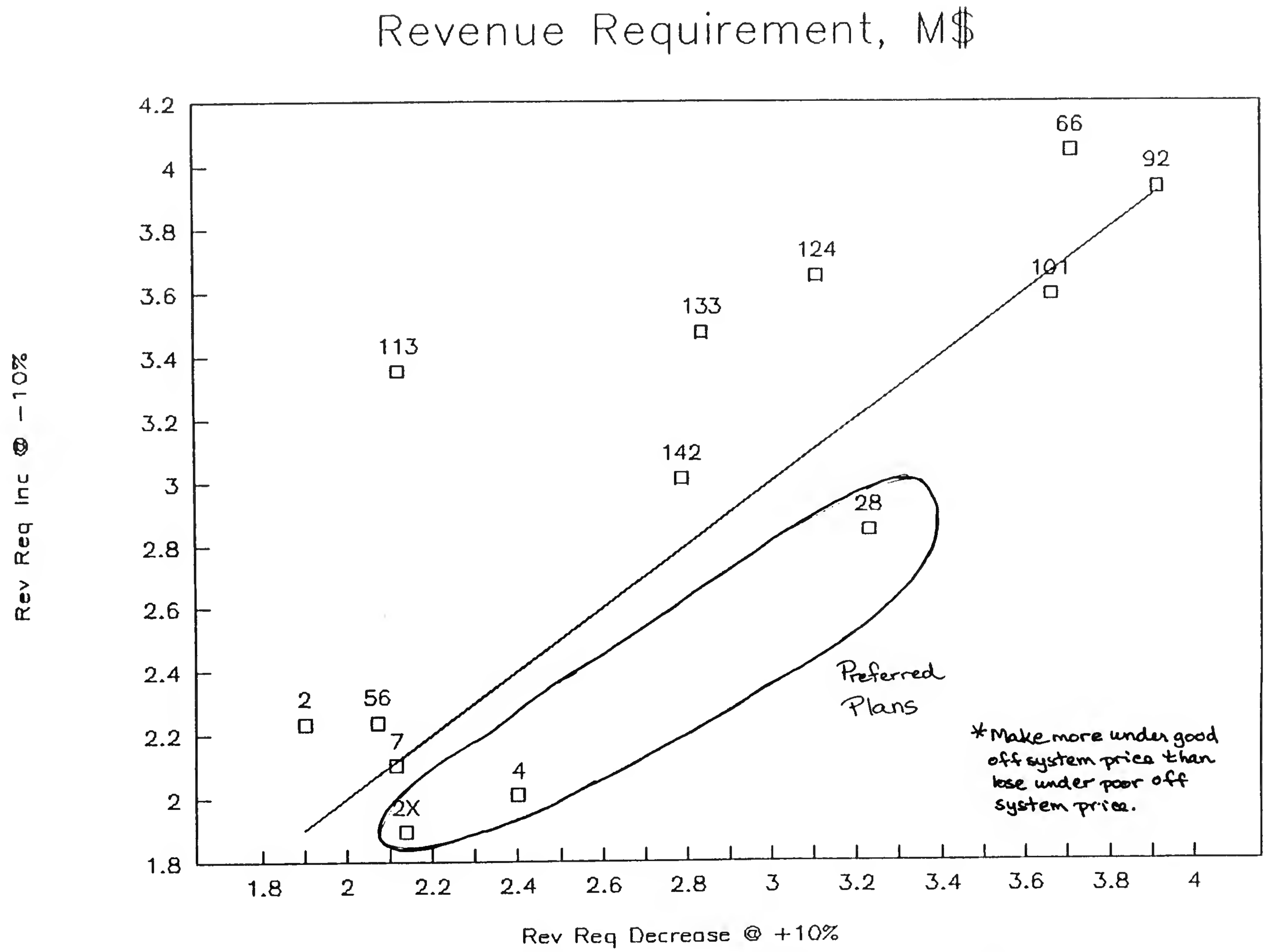
GRAPH # DSMRU2 Levelized Return on Equity

This graph shows, from the owner return on equity perspective, the return on equity improves with less DSM. The comparison between graphs DSMRU1 and DSMRU2 <u>clearly</u> identifies the lost revenue decline which MPC is currently addressing through its advisory committee.


ECONOMY SALES PRICE −10%
DIFF FROM BASE CASE
TTL REV REQ, M$ INCREASE
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
2
4
7
56
92
124
66
101
113
133
142
28
2X
PLAN #

GRAPH ERU1


ECONOMY SALES PRICE +10%
DIFF FROM BASE CASE
TTL REV REQ, M$ INCREASE
0
-0.5
-1
-1.5
-2
-2.5
-3
-3.5
-4
-4.5
2
4
7
56
92
124
66
101
115
133
142
28
2X
PLAN #
GRAPH ERU2


Revenue Requirement, M$
Rev Req Inc @ −10%
Rev Req Decrease @ +10%
4.2
4
3.8
3.6
3.4
3.2
3
2.8
2.6
2.4
2.2
2
1.8
1.8
2
2.2
2.4
2.6
2.8
3
3.2
3.4
3.6
3.8
4
66
92
124
101
133
113
142
28
2
56
7
4
2X
Preferred Plans
*Make more under good off system price than lose under poor off system price.

GRAPH ERU3

ECONOMY SALES UNCERTAINTY

GRAPH # ERU1 & ERU2 Economy Sales difference from Base Case (-10% & +10%)

Plans which have the most surplus are most sensitive to economy sales price. Plans 92, 124, 66, 101, 113, 133, 142 contain a large base load resource (Westmoreland or LS Power) and are most sensitive to economy sales changes than the remaining plans.

Rev. Req. Difference Between 92 ...142 and Remaining Plans

+10%	$0.8 Million Revenue Requirement Decrease
-10%	$1.3 Million Revenue Requirement Increase

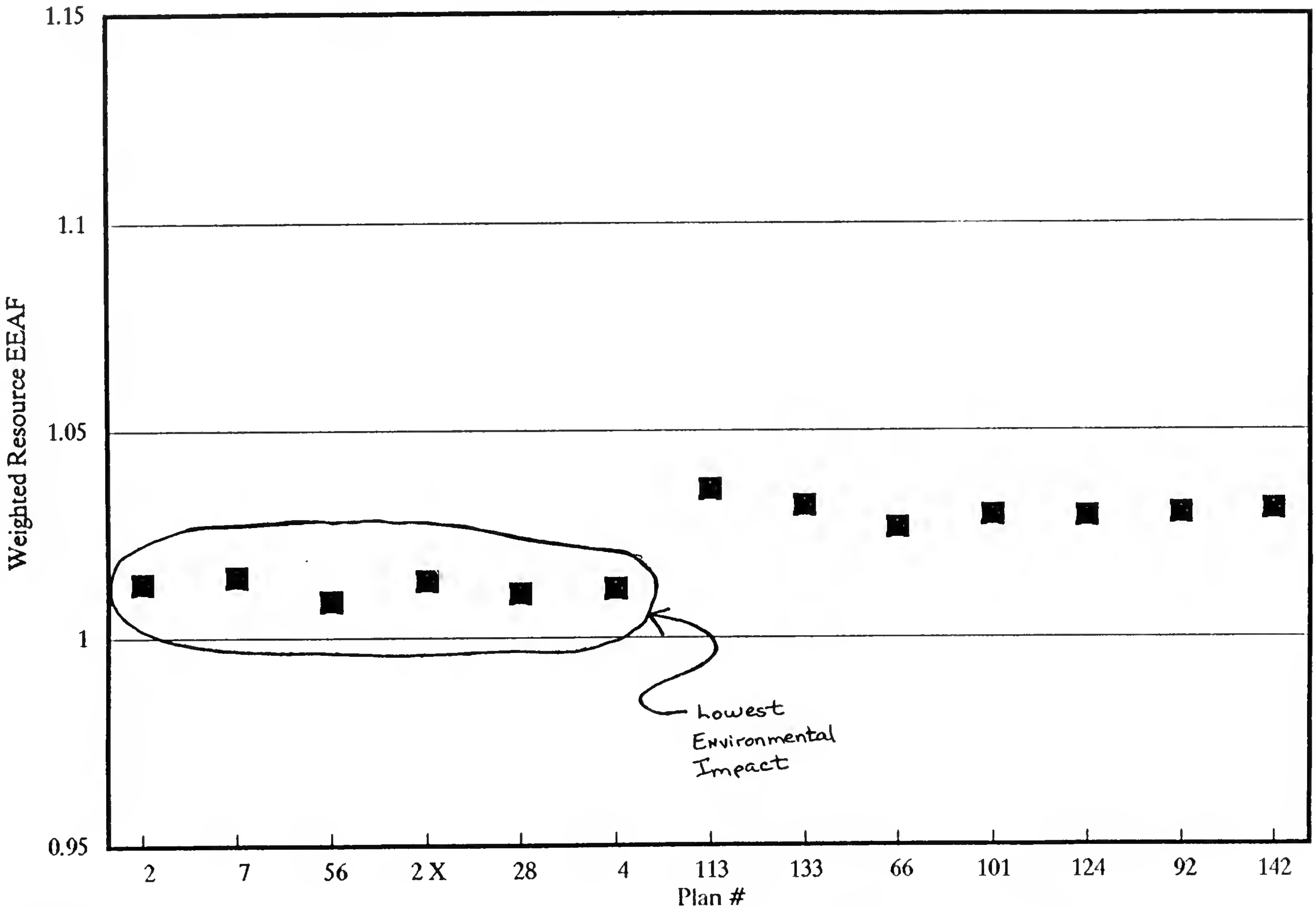
GRAPH # ERU3 Revenue Requirement comparison to +10% & -10%

This graph shows the non linear nature of the +10% and -10% economy sales price change on revenue requirements. Most plans lose more money under poor economy sales prices (-10%) than they gain under good prices (+10%). Plans 28, 2X and 4 gain more money under good prices than they lose under poor prices. These plans are preferred. Plans 7, 92, and 101 gain and lose about the same amount of money under good and poor prices.

NOTE:

(1) Transmission constraints to our economy markets could be a problem for resource plans with large amounts of surplus energy.

PLAN EQUIVALENT EEAF



stat.wk3

GRAPH EERU1

ENVIRONMENTAL IMPACT

NON QUANTIFIABLE RISK

* Static Analysis: The same set of resources would have been selected using both a higher and lower environmental externality adjustment factor. This is true because of MPC's selection criteria.

* Dynamic Analysis: Stone C (DSM2) proposal is the most sensitive to higher EEAF values.

* MPSC or others could advocate another method to address environmental externalities.

* MPSC or others could take issue with the carbon dioxide weighting used by MPC.

* Future NOx regulation may have impacts not identified by MPC matrix.

ENVIRONMENTAL UNCERTAINTY BY RESOURCE

Antelope

* Apparently will meet SO_2 requirements
* May have CO_2, carbon tax or NOx exposure.

Tiber Dam

* Benign resource
* Possible down stream aquatic improvement

LS Repower of Bird

* Will reduce SO_2 and particulate emissions
* Project SO_2 removal may not be as high as sponsors predict
* May have CO_2, carbon tax or NOx exposure
* Cooling water discharge permit
* CO_2 emissions risk is it in or out of Billings non-attainment area?

Westmoreland

* NOx regulation, and plan to install selective catalytic reduction

Stone B & C Projects

* There is a decrease in particulate emissions during operation
* Cooling water discharged into Clarks Fork River
* NOx regulation risk
* CO2 risk, outside Missoula non-attainment area, but upwind

MPC Bird

* NOx regulation
* Base load may limit Corette production in summer because of cooling water discharge temperature.

Ryan

* Impacts will be mitigated

Thompson Falls

* Impacts have already been mitigated
* Noise may be concern

TRANSMISSION UNCERTAINTY

* In general, transmission losses are less the farther west the resources are located on MPC's system.

* Highest transmission losses occurred when Westmoreland was included.

* Plans 2 and 7 showed potentially adverse effects when outages occur in areas specific to the resources being added. (These plans will aggravate a problem that will occur without these added resources.)

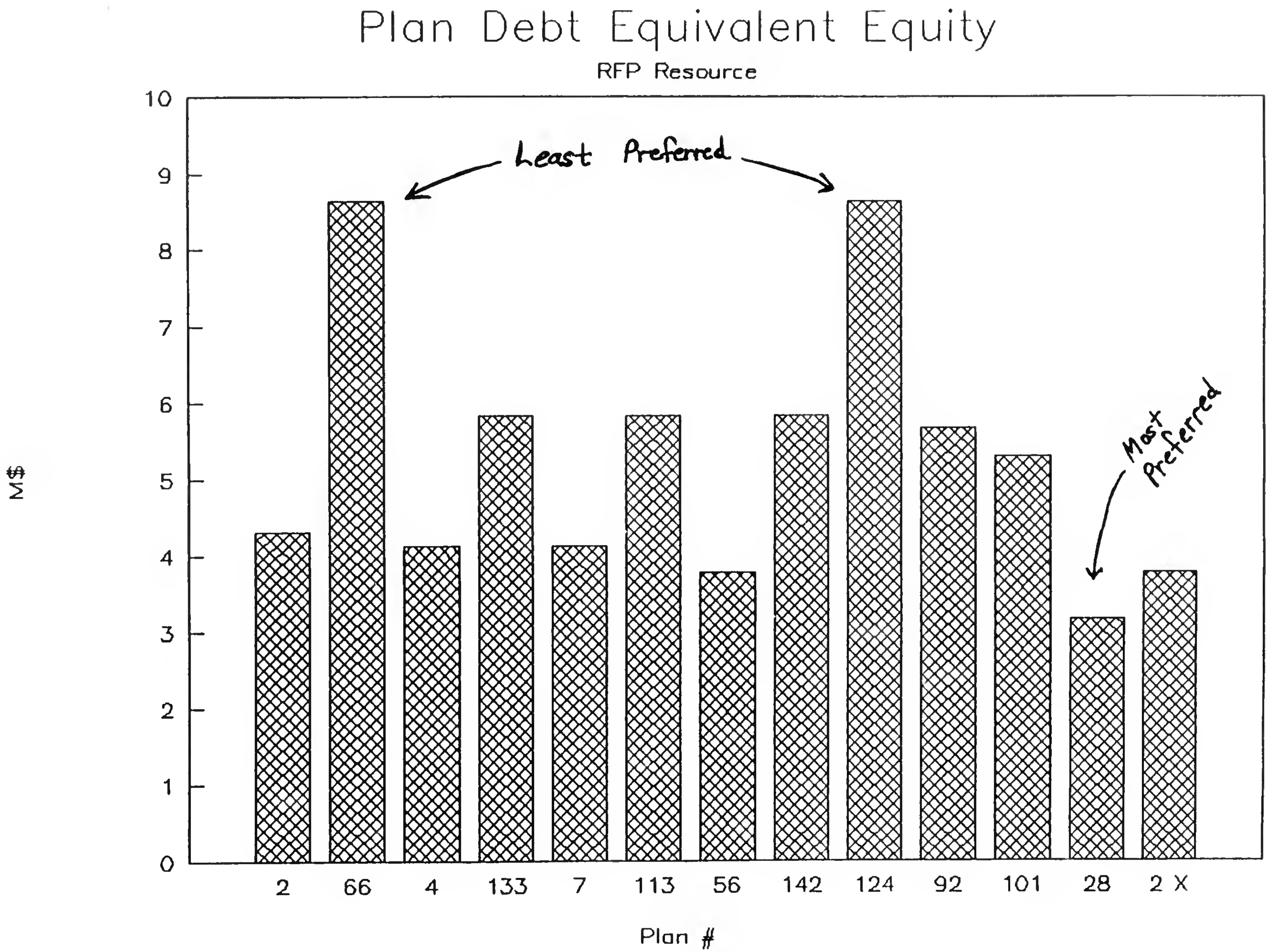
* Plans with Westmoreland could result in an auto-transformer overloading.

* Present transfer capability to the Northwest may limit the ability to sell excess during non-peak load periods.

* Plans with the Stone projects (B and C) improve voltage levels in Missoula. However, the improvements are not great enough to delay or defer planned transmission facilities in the area.

* Tiber must wheel across WAPA to get to the MPC system.

* Ryan: FERC may mandate removal of one of the Ryan/Rainbow 100 KV lines. If this happens, the remaining line would have to be reconstructed. This cost was not considered in the analysis.


Plan Debt Equivalent Equity
RFP Resource
M$
10
9
8
7
6
5
4
3
2
1
0
2
66
4
133
7
113
56
142
124
92
101
28
2 X
Plan #
Least Preferred
Most Preferred

GRAPH DEE1

DEE UNCERTAINTY

GRAPH # DEE1 Plan Debt Equivalent Equity

Plan 28 has lowest DEE costs. Plan 66 and 124 have the highest DEE costs.

RELIABILITY UNCERTAINTY

<u>Antelope Purchase (Basin)</u>

* Existing unit has been operating reliably
* Mine mouth coal is a reliable fuel source
* Failure of the Miles City converter station would cause transmission reliability problems

<u>Tiber Dam</u>

* Run of river operation will have minimum stress on equipment
* Reliability of WAPA interconnection unknown

<u>Bird Repowering - LS Power</u>

* Availability factor of 88% may be high (85%)
* Very reliable fuel supply
* 14 days of secondary fuel (coal)
* Very good transmission reliability

<u>Westmoreland</u>

* 95% availability factor
* Shouldn't be a fuel supply problem
* Transmission reliability should be good
* Plant is subject to generator dropping off line during system instability events

<u>Stone B</u>

* Operated at 100% capacity factor except during maintenance
* No fuel supply problem

<u>Stone C</u>

* Energy production questions, may be high
* No fuel supply problem

<u>Ryan</u>

* No problems

<u>Thompson Falls</u>

* No problems

TECHNICAL UNCERTAINTY

Generally, all plans are technically sound.

<u>Minor Technical Aspects</u>

* Bird Repowering - LS Power: Capacity factor of 93% seems high (87%)
* Westmoreland: Capacity factor of 98% seems high (95%)
* Stone B & C: Capacity factors may be high, but may be true in industrial applications.

RESOURCE COST UNCERTAINTY

The following is a summary of the risk and uncertainty review for resource cost. This includes a quantification of the PROSCREEN results and a discussion of those elements which are more subjective in nature.

#6 - ANTELOPE

This proposal from Basin Electric includes a caveat that 'MPC will be requested to share in capital improvements required'. We should investigate the condition of this resource and make a clearer definition of our future liability in the final contract.

One risk which MPC will be asked to share is future requirements of the Clean Air Act. This project meets the SO_2 requirements but may require modifications for NO_X. In addition future requirements for CO_2 could create a liability.

MPC will be expected to pay our share of the actual fixed and variable costs for Antelope for the duration of the contract. The base case escalated these non fuel costs using a DRI CPI index for the term of the contract. The high resources cost assumed an escalator of 7%.

#14 - Tiber Dam

Continental Hydro Corporation's bid for Tiber Dam is fixed price for both the energy and capacity and there seems to be little risk to the project from inflation rates higher than the current projections. Variations of resource cost were not performed for this proposal.

#35 - Bird Repowering

The capacity payment for LS Power's project is based on the cost of capital as of December 17, 1991 and will change up or down depending on the actual financing cost at closing of construction financing.

The energy bid is the higher of the energy floor price supplied by LS Power or a percentage of MPC's actual avoided system energy costs. The bid was evaluated using LS Power's energy floor price while the high resource case substituted a percentage of MPC's June 1992 avoided costs filing. The energy price from the avoided cost filing is different than an actual avoided energy cost that would be calculated monthly. Under current conditions the monthly actual avoided cost calculation should not result in a value that would replace LS Power's energy floor price. However, we should insure that this subject is treated explicitly in contract negotiations to insure an accurate definition of the calculation and a clear understanding by MPC on the affect of future resources on the calculation.

#B & C - Stone Container

Both of the Stone bids are escalated at a fixed annual rate. These two bids are not tied to any index and thus there is no exposure in upward changes in the inflation rate.

#66 - Westmoreland Combined Cycle

In the base case,the fixed O & M is escalated at 90% of the CPI and the variable O & M is escalated at 25% of the CPI. The CPI averaged about the rate of inflation in the base case. In the high case, the CPI was changed to a flat 7% annually.

Bird Peaking and Firming

In the base case,Bird's costs were escalated at 5.09%. In the high case Bird's costs were escalated at 7%.

Thompson Falls Upgrade and Ryan Upgrade

In the base case,the costs were escalated at about the rate of inflation and in the high case,these costs were escalated at 7%.

Other Analysis Summary

EEAF Analysis

Purpose: Identify RFP resources and develop resource plans using on of the following conditions.

-no environmental externality adjustment factor (EEAF).

-air emission adders similar to New York's adders and MPC environmental matrix assessment of other environmental impacts.

Observations:

The same set of resources would have been selected in the static analysis if different levels of EEAF were used.

In the dynamic analysis, resource C is replaced when higher air emissions impact costs are used.

DSM Resource Flexibility Analysis

Purpose: Identify resource flexibility required in the other resources if the "SSSS" or the "AAAA" acquisition levels are achieved.

Observations:

Required flexibility is plan dependent.

Moving from the "SASA" demand-side acquisition to...

the "SSSS" acquisition level, resources are generally added and earlier timing of some of the resources is required.

the "AAAA" acquisition level, resources are generally eliminated.

DEE Analysis

Purpose: Build resource plans with no debt equivalent equity (DEE) for purchase power.

Observations:

A re-configuration of the selected resources within some of the base plans occurred.

In one base plan a pulverized coal unit was included when no

DEE was used in the dynamic analysis.

Expected Water Resource Plan Analysis

Purpose: Determine if expected water hydro production logic would have changed RFP resource selection.

Observations:

In general, the same base plans would have been selected with the possibility of different resource timings.

Possibility of Bird peaking alternative converted to Bird firming resulting in the elimination of Stone B.

Resource Changes		
No EEAF Plans	MPC EEAF Plans	"NY" EEAF Plans
Plan 2 --------->	Plan 2 --------------->	Plan 2
	-no change	-no change
Plan 4 --------->	Plan 4 --------------->	Plan 20
	-no change	-C eliminated -Bird peaking to firming -T.Falls 3yr earlier -Basin 1yr earlier
Plan 7 --------->	Plan 7 --------------->	Plan 11
	-no change	-C eliminated -Bird peaking to firming -Ryan 2 yrs earlier -Basin 1yr earlier
Plan 60 -------->	Plan 56 -------------->	Plan 23
	-no change	-C eliminated -B included -Bird firming included -T.Falls 3yr later
Plan 82 -------->	Plan 124 ------------->	Plan 105
	-B eliminated -C eliminated -Basin included -Westmoreland 1yr earlier	-no change
Plan 64 -------->	Plan 92 -------------->	Plan 79
	-C eliminated -Ryan eliminated -T.Falls included -Basin included	-no change

This table clearly shows that as the EEAF value increased resource C is replaced by alternative resources. In the Plan 64 sequence, Ryan is probably replaced in resource plan 92 because of energy need created when C is eliminated and not because of a different EEAF.

Conclusion

The conclusion from this analysis are as follows.

> The same set of resources would have been selected in the static analysis and passed to the dynamic analysis.

> In the dynamic analysis, the selection of resource C (i.e. Stone Container proposal DSM2) is sensitive to increased EEAF value.

Demand-Side Alternative
Resource Additions, Deletions
And Timing Changes

SSSS Plan <------	SASA Plan ---->	AAAA Plan
Plan 45 <-------------------	Plan 2 --------->	Plan 1
-B eliminated -C eliminated -Tiber eliminated -Westmoreland added		-B eliminated -Tiber eliminated
Plan 1 <--------------------	Plan 4 --------->	Plan 35
-Tiber added -T.Falls 3yr earlier -Basin 1yr earlier -B 1yr later		-C eliminated -Tiber added -T.Falls 3yr earlier
Plan 3 <--------------------	Plan 7 --------->	Plan 17
-Bird peaking eliminated -Bird firm added -Ryan 2yr earlier -Basin 1yr earlier -B 4yr later		-Ryan 2yr earlier -B 1yr later
Plan 18 <-------------------	Plan 56 -------->	Plan 25
-B added -Bird peaking added -Tiber added -Ryan 2yr later		-B added -T.Falls 3yr later -Basin 1yr later
Plan 45 <-------------------	Plan 124 ------->	Plan 185
-no change		-Basin eliminated -Ryan added
Plan 57 <-------------------	Plan 92 -------->	Plan 116
-B eliminated -C added		-T.Falls eliminated -Ryan added

Conclusion

The resource flexability is plan dependent.

Resource Change
No DEE

Base Plan -------->	No DEE Plan (W/O Tiber or B)
Plan 2 ----------->	Plan 11 -No Tiber or B -C eliminated -Westmoreland CC added
Plan 5 ----------->	Plan 5 -No B -T.Falls 3yr earlier
Plan 7 ----------->	Plan 1 -No B -Basin eliminated -IPC exchange eliminated -C eliminated -Westmoreland PC added -Ryan 1yr earlier
Plan 56 ---------->	Plan 16 -No change
Plan 124 --------->	Plan 11 -No change
Plan 92 ---------->	Plan 47 -No B -Ryan added -T.Falls 3yr later -Basin 1yr later -LS 1yr earlier

Conclusion

A different resource stack is possible if no DEE were used in the dynamic analysis.

Resource Change
Expected Water Timings

Base Plan ----->	Exp(H20) Plan
Plan 2 -------->	Plan 2 -No change
Plan 4 -------->	Plan 4 -No change
Plan 7 -------->	Plan 31 -Bird Peaking eliminated -B eliminated -Bird Firming added -Ryan 2yr earlier -Basin 1yr earlier
Plan 56 ------->	Plan 54 -No change
Plan 124 ------>	Plan 119 -No change
Plan 144 ------>	Plan 144 -LS 1 yr earlier -B 1 yr later -Basin 1 yr later

Expected value refers to the amount of generation available from the hydro system under good, average and poor water conditions. The expected value of production costs are developed by running the production costing module three times, each with different energy available from the hydro system. The three sets of results are then multiplied by their water condition probability of occurrence to get the expected value of production costs. The following table applies.

Water Condition	Avg MW Energy	Probability
Poor	335	12%
Average	385	76%
Good	425	12%

Conclusion

Using expected water did not change the resource mix in five out of the six resource plans. In two of the six resource plans, re-timing of some of the base case resources did occur. In one of the six plans, Stone B was replaced when Bird peaking was converted to Bird firming.